Sanchez Energy Corp
Form 10-K
March 01, 2019
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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.

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SANCHEZ ENERGY CORPORATION

FORM 10 K

FOR THE YEAR ENDED DECEMBER 31, 2018

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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");

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- 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;

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- 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.”

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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.

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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

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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

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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,

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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 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.

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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

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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.

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| | 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.

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(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."

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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.”

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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.

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(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 |

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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.

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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.

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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

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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

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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

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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.

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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 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.

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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

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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.

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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

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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.

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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

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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

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- 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:

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- 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.

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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

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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;

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· 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

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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.

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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;

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- 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

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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;

· adverse weather conditions and natural disasters;

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

· title problems;

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

· compliance with ever changing environmental and other governmental requirements;

· environmental hazards, such as chemical or hydrocarbon leaks or spills, salt water leaks or spills, pipeline ruptures, discharges of toxic gases or other releases of hazardous substances;

· lost or damaged oilfield development and service tools;

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

· loss of drilling fluid circulation;

· fires, blowouts, surface craterings and explosions;

· uncontrollable flows of oil, natural gas, NGLs or well fluids;

· loss of leases due to incorrect payment of royalties;

· limited availability of financing on acceptable terms, or at all; and

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

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

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

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

Trading in our common stock on the NYSE was suspended on February 20, 2019, and the NYSE has notified us that our common stock is subject to delisting proceedings. At this time, we expect that the NYSE could file a Form 25 to delist our common stock as early as March 7, 2019. Our common stock is quoted only in the over-the-counter market, which could negatively affect our stock price and liquidity.

On December 21, 2018, the Company received written notice from the NYSE that the average closing price of its common stock over a period of 30 consecutive trading days was below $1.00 per share, which is the minimum average closing price per share required to maintain listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual (the "NYSE LCM"). In accordance with applicable NYSE procedures, the Company notified the NYSE of its intent to pursue actions to meet the minimum average share price requirement and restore its compliance with the relevant standards required in Section 802.01C within the six-month period allowed by the NYSE.

Additionally, on January 3, 2019, the Company received written notice from the NYSE that the decline in the Company's total market capitalization has caused it to be out of compliance with an additional continued listing standard. Rule 802.01B of the NYSE LCM requires that a company maintain an average market capitalization of at least $50 million over a period of 30 consecutive trading days, unless at the same time the company's total stockholders' equity is equal to or greater than $50 million. In accordance with applicable NYSE procedures pertaining to non-compliance due to low market capitalization, the Company had until February 19, 2019 to submit a plan to meet the minimum market capitalization requirement within 18 months and restore its compliance with the NYSE continued listing standards.

The Company thereafter did not submit a plan of compliance within the required timeframe that, if accepted by the NYSE, would have allowed our common stock to remain on the NYSE for a period of 18 months in order for us to bring the Company into conformity with the Rule 802.01B market capitalization standard (subject to compliance with the NYSE's other continued listing standards and continued NYSE review of our progress). On February 20, 2019, the Company received a written notice from the NYSE that, based on the foregoing, our common stock was subject to delisting proceedings. Although the NYSE LCM provides the Company limited rights to seek a review of the NYSE's determination, the Company has elected not to seek any such review or otherwise appeal the NYSE's determination. Trading in the Company's common stock was suspended at the market opening on February 20, 2019. At this time, the Company expects that the NYSE could file a Form 25 to delist the Common Stock as early as March 7, 2019, following

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the conclusion of the 10 business day review and appeal period. Under Rule 12d2-2(d)(1) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), an application on Form 25 to strike a class of securities from listing on a national securities exchange will be effective 10 days after the filing of the Form 25.

Our common stock is currently quoted on the OTC Pink market (OTC Pink: SNEC), although there is no assurance that an active market in the common stock will develop. Securities quoted in the over-the-counter markets are not considered to be traded on a national exchange. Even if the common stock remains quoted on the OTC Pink, the delisting of our common stock from the NYSE could negatively impact the Company, as it will likely reduce the liquidity and market price of the common stock; reduce the number of investors willing to hold or acquire the common stock; negatively impact the Company’s ability to access equity markets and obtain financing; and impair the Company’s ability to provide equity incentives.

Our stock price has declined significantly, and investors in our common stock could incur substantial losses if our stock price remains depressed.

During the year ended December 31, 2018, our stock price declined from a high closing price of $5.99 per share on January 12, 2018 to a low closing price of $0.25 per share on December 27, 2018. As a result of this extended decline, investors may not be able to recover their investment in us. The market price for our common stock may be influenced by many factors, including, but not limited to:

- the price of oil, natural gas and NGLs;

- the success of our exploration and development operations, and the marketing of any hydrocarbons we produce;

- our ability to access equity financing while quoted in over-the-counter securities markets rather than listed on a national stock exchange;

- regulatory developments in the United States;

- the recruitment or departure of key personnel;

- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;

- market conditions in the industries in which we compete and issuance of new or modified securities;

- analyst reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- higher than achievable estimates by analysts who follow our common stock;
- our issuance of any additional securities;
- investor perception of the Company and of the industry in which we compete;
- our ability or inability to restructure or refinance our indebtedness;
- filing for relief under the U.S. Bankruptcy Code; and
- general economic, political and market conditions.

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In addition, if we undertake one or more strategic or financing transactions it would likely 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. See "—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, such alternatives could adversely affect our creditors and put our stockholders at significant risk of losing all of their respective investments in us."

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

Our current business focus is on the exploration and production of oil and natural gas in a limited number of properties, in the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Southwest Mississippi and Southeast Louisiana. Larger companies have the ability to manage their risk by diversification. However, we currently lack diversification, in terms of both the nature and geographic scope of our business. For example, our Catarina assets, comprising approximately 106,000 contiguous net acres in Dimmit, La Salle and Webb counties, Texas under the Catarina Lease, represent approximately 58% of our proved reserves, approximately 39% of our Eagle Ford acreage and approximately 52% of our total production volumes for the year ended December 31, 2018. As a result, we will likely be impacted more acutely by factors affecting our industry or the regions in which we operate than we would if our business were more diversified, increasing our risk profile. In particular, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from wells in the Eagle Ford Shale. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our acquisition, development and production operations require us to make substantial capital expenditures. Although we expect to fund our capital expenditure budget for 2019 using cash flow from operations and cash on hand, if our cash flow from operations turns out to be less than we currently expect and we are required, but are unable, to fund our remaining capital budget from other sources, such as borrowings under the credit agreements and/or the issuance of debt or equity securities, our failure to obtain the funds that we need could have a material adverse effect on our business, financial condition and results of operations.

The oil and natural gas industry in which we operate is capital intensive and we must make substantial expenditures in our business for the acquisition, development and production of oil, natural gas and NGLs. During 2018 we invested approximately $593 million for drilling and completion activities in our core areas. For 2019, we have set a capital budget of approximately $100 million to $150 million, which we anticipate funding primarily with cash on hand and cash flow from operations. We expect our planned reductions in development activity in 2019 to cause our production to decline, which will begin to reduce our revenue, cash flows and possibly our reserves (particularly if commodity prices remain low and, as a result of low commodity prices or other circumstances we did not anticipate or which are beyond our control, our capital expenditures budget does not return in 2020 to amounts comparable to our historic (pre-2019) levels).

Our cash on hand, cash flows from operations, ability to borrow and access to capital markets are subject to a number of variables, many of which are beyond our control, including:

- our estimated reserves of proved oil, natural gas and NGLs;
- our ability to successfully execute on our drilling and development programs;
- the amount of oil, natural gas and NGLs we produce;

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- the prices at which we sell our production;
- the results of our hedging strategy;
- the costs of developing, producing, and transporting our oil, natural gas and NGLs, including costs attributable to governmental regulation and taxation;
- our ability to acquire, find and produce new reserves;
- fluctuations in our working capital needs;
- interest payments, debt service and dividend payment requirements;
- our ability to comply with the financial covenants in our debt instruments, to repay our debt, and to address our near-term liquidity needs, particularly if oil and natural gas prices remain volatile and/or depressed;
- prevailing economic and capital markets conditions, especially for oil and natural gas companies;
- our financial condition; and
- the ability and willingness of banks and other institutions to lend to us.

In addition, we may be unable to access the capital markets for debt or equity financing. If we are unsuccessful in obtaining the funds we need to execute our capital budget, we will be forced to further reduce our capital expenditures, which in turn could lead to additional declines in our production, revenues, cash flows and our reserves, and could further adversely affect our business, financial condition and results of operations.

Furthermore, our ability to borrow under the Credit Agreement or UnSub Credit Agreements is or may be limited or such borrowings may be unavailable to fund our capital expenditures. For example, as of February 26, 2019, we had approximately $17.1 million in letters of credit outstanding under the Credit Agreement and no borrowings, resulting in less than $8 million in availability for borrowings or additional letters of credit. Failure to comply with certain operational covenants under the Credit Agreement or UnSub Credit Agreement could result in events of default in the future that would restrict our access to capital and/or accelerate our payment obligations. In addition, in December 2018, the borrowing base under the UnSub Credit Agreement was reduced from $380 million to $315 million and may be further reduced in the future.

A portion of our oil and natural gas production is subject to commodity derivative contracts and the price we receive for such production is dependent on conditions in the market at the time we enter into such contracts.

On a consolidated basis, the Company has hedged approximately 3,149,000 Bbls of its 2019 oil production and 17,644,000 MMBtu of its 2019 natural gas production. SN UnSub’s production represents approximately 54% of the hedged oil volumes and approximately 59% of the hedged gas volumes. In the future, we expect to continue to enter into commodity derivative contracts for a portion of our estimated production, which could result in net gains or losses on commodity derivatives. Our hedging strategy and future hedging transactions will be determined by our management in accordance with the terms of SN UnSub’s organizational documents and any restrictions or limitations in our debt instruments.

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

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

Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production in paying quantities is established during their primary terms or we obtain extensions of the leases. Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, 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 do not know if our undeveloped leasehold acreage will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. If our leases expire and we do not have them held by production, we will lose our right to develop the related properties on this acreage.

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. While we anticipate that our current and future drilling plans along with selected lease extensions will address the majority of our leases expiring in the Eagle Ford Shale in 2019, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation.

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

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

Our operations could be disrupted if our or SOG's information systems are hacked or fail, causing increased expenses and loss of revenue.

We face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data systems unusable, and threats to the security of our facilities and infrastructure, SNMP facilities or infrastructure or other third-party facilities and infrastructure, such as pipelines. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business.

Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including such systems of SOG that we utilize pursuant to the Services Agreement with SOG. We process transactions on a daily basis and rely upon the proper functioning of computer

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systems. If a key system were hacked or otherwise interfered with by unauthorized access, or were to fail or experience unscheduled downtime for any reason, even if only for a short period, our financial results could be affected adversely.

Additionally, we rely on information systems across our operations, including for the management of processes and transactions. A disruption to any information systems at our operating locations, or at SNMP's or a third-party's pipelines, terminals, operating locations or other facilities may cause disruptions to our operations. These systems could be damaged or interrupted by a security breach, cyber-attack, fire, flood, power loss, telecommunications failure or similar event. Further, our business interruption insurance may not compensate us adequately for losses that may occur. Additionally, federal legislation relating to cybersecurity threats could impose additional requirements on our operations. Finally, our implementation of additional procedures and controls in response to such legislation or to otherwise monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs.

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

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

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

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

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

There are a variety of operating risks inherent in our wells and other operating properties and facilities, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal

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injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells and other operating properties and facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

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

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

We do not operate all of the properties in which we own an ownership interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these non operated properties. The failure of an operator of our wells to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in ways that are in our best interests could reduce our production, revenues and reserves. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

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

- the operator’s selection of suitable technology.

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

Water is an essential component of oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in our areas of operation in past years. These drought conditions have led governmental authorities to restrict the use of water, subject to their jurisdiction, for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

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Furthermore, the Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other oil and natural gas waste into navigable waters. In addition, the underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Public concerns regarding the potential impacts to groundwater and induced seismic activity have resulted in new requirements related to the underground injection and disposal of fluids. The EPA is also 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. Compliance with environmental regulations and permit requirements governing the discharge of underground injection of fluids and the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

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

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

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

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

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with their owners;

- unable to obtain financing for such acquisitions on economically acceptable terms; or

- outbid by competitors.

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

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

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

- mistaken assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs, including synergies, timing of expected development and the potential for expiration of underlying leaseholds;

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

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

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

We have extended the term of our net operating loss carryforwards (“NOLs”) Rights Plan, which may discourage the acquisition and sale of large blocks of our common stock and may result in significant dilution for certain stockholders.

On July 27, 2018, the Company entered into Amendment No. 2 to the NOL Rights Plan (as amended, the “Rights Plan”) designed to preserve stockholder value and the value of our NOLs by acting as a deterrent to any person acquiring beneficial ownership of 4.9% or more of the Company’s outstanding common stock without the approval of our board of directors. The extension of the Rights Plan may depress the market price of our common stock, as it may reduce the liquidity of the Company’s common stock by discouraging existing 5% common stockholders from selling their interests in a single block and may deter institutional investors from investing in our common stock or potential acquirers from making premium offers to acquire the Company. We can make no assurances the Rights Plan will be effective in meeting its intended objectives, including to deter a change in control and protecting or realizing NOLs.

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If we were to experience an ownership change, we could be limited in our ability to use NOLs arising prior to the ownership change to offset future taxable income. In addition, our ability to use NOLs to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2018, we had NOLs of $2,028.8 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long term tax exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three year period. Future changes in the ownership of our stock, including changes as a result of any restructuring or recapitalization transactions (pursuant to the U.S Bankruptcy Code or otherwise), may trigger an "ownership change."

In addition, as a result of the Tax Act, NOLs arising before January 1, 2018, and NOLs arising on or after January 1, 2018, are subject to different rules. NOLs arising before January 1, 2018 can generally be carried forward to offset future taxable income for a period of 20 years. Any NOLs arising on or after January 1, 2018, while subject to additional limitations, can generally be carried forward indefinitely. Our ability to use our NOLs during this period will be dependent on our ability to generate taxable income, and the NOLs could expire before we generate sufficient taxable income to make use of our NOLs.

Despite our current level of indebtedness and recent borrowing base decrease, we may be able to incur substantially more debt. This could exacerbate the risks associated with our indebtedness.

Despite our current level of indebtedness and a recent borrowing base decrease under the SN UnSub Credit Agreement, we and our subsidiaries may be able to incur substantial additional indebtedness in the future, including under the SN UnSub Credit Agreement. As of December 31, 2018, we had $2.4 billion of debt outstanding, net of premium, discount and debt issuance costs, the majority of which was attributable to the Senior Notes (as defined in "Item 8. Financial Statements and Supplementary Data – Note 6, Debt"), a $25 million commitment to provide primarily for working capital and letters of credit under the Credit Agreement, and a borrowing base of $315 million under the SN UnSub Credit Agreement, of which $167.5 million in borrowings was drawn at year end.

Our increased indebtedness could adversely affect our business. In particular, the incurrence of additional debt could increase our vulnerability to sustained, adverse macroeconomic weakness, expose us to additional debt service, covenant compliance and other obligations, limit our ability to obtain further financing and limit our ability to pursue certain operational and strategic opportunities. If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

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

We are subject to interest rate risk in connection with borrowings under the Credit Agreement, the SN UnSub Credit Agreement and the SR Credit Agreement, all of which bear interest at variable rates. Interest rate changes could affect the amount of our interest payments under these credit facilities and, accordingly, our future earnings and cash flows, assuming other factors are held constant. We currently do not have any interest rate hedging arrangements with respect to our credit facilities. In the future, we may enter into interest rate swaps in order to reduce our exposure to interest rate volatility; however, any swaps we enter into may not fully mitigate our interest rate risk. A significant increase in prevailing interest rates that results in a substantial increase in the interest rates applicable to our indebtedness could substantially increase our interest expense and have a material adverse effect on our financial condition and results of operations.

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Restrictive covenants may adversely affect our operations.

The Credit Agreement, the indentures governing the Senior Notes (as defined in Item 8. Financial Statements and Supplementary Data — Note 6. Debt), the SN UnSub Credit Agreement and the SR Credit Agreement contain a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long term best interest, including our ability, among other things, to:

· incur or assume additional debt or provide guarantees in respect of obligations of other persons;

· issue redeemable stock and preferred stock;

· pay dividends or distributions or redeem or repurchase capital stock;

· prepay, redeem or repurchase certain debt;

· make loans and investments;

· create or incur liens;

· restrict distributions from our subsidiaries;

· sell assets and capital stock of our subsidiaries;

· consolidate or merge with or into another entity, or sell all or substantially all of our assets; and

· enter into new lines of business.

Additionally, if dividends on our Series A Preferred Stock or Series B Preferred Stock are in arrears and unpaid for six or more quarterly periods, the holders (voting as a single class) of our outstanding Series A Preferred Stock and/or Series B Preferred Stock will be entitled to elect two additional directors to our board of directors until paid in full. Furthermore, unless all accumulated and unpaid dividends are declared and paid on the Series A Preferred Stock and Series B Preferred Stock, no dividends or other distributions (other than a dividend or distribution payable solely in shares of parity stock or junior stock, under certain circumstances, and cash in lieu of fractional shares) may be declared, made or paid, or set apart for payment upon, any parity stock or junior stock (including our common stock), nor may any parity stock or junior stock (including our common stock) be redeemed, purchased or otherwise acquired for any consideration by us or on our behalf, except in limited circumstances. Covenants contained in the Credit Agreement, future credit facilities we may enter into, our indentures and the certificates of designations for our preferred stock restrict our ability to pay dividends on our Series A Preferred Stock and Series B Preferred Stock. In addition, the Delaware General Corporation Law (the "DGCL") permits payment of dividends only out of a corporation's surplus, which is defined as the excess of net assets (total assets less total liabilities) over a corporation's capital as determined under the DGCL. If commodity prices remain at the depressed levels to which they declined during the fourth quarter of 2018, the value of our net assets will consequently remain depressed and our ability to lawfully declare and pay dividends will decline.

A breach of the covenants under the indentures governing the Senior Notes, the covenants under the Credit Agreement or the covenants under the SN UnSub Credit Agreement and SR Credit Agreements could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt that contains a cross acceleration or cross default provision (however, a default under the Credit Agreement or the Senior Notes would not result in a default under or the acceleration of the SN UnSub Credit Agreement or SR Credit Agreement and a default under the SN UnSub Credit Agreement or SR Credit Agreement would not result in a default under or the acceleration of the Credit Agreement or Senior Notes). Moreover, an event of default may, under certain circumstances, allow counterparties to our hedge agreements to terminate the hedge transactions to which they are a party, which termination could occur at an unfavorable time and result in cash settlement payments, losses or reductions in income. In addition, an event of default under the Credit Agreement or the

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SN UnSub Credit Agreement would permit the lenders under the relevant facility to terminate all commitments to extend further credit under that facility. If we were unable to repay those amounts or amounts due to holders of our 7.25% Senior Secured Notes or the lender under the SR Credit Agreement, the lenders under the Credit Agreement, the SN UnSub Credit Agreement or the SR Credit Agreement or the holders of our 7.25% Senior Secured Notes, as applicable, could proceed against the collateral granted to them to secure that debt. See “Item 8. Financial Statements and Supplementary Data – Note 10, Related Party Transactions.”

Because we have no plans to pay dividends on our common stock and have suspended our preferred stock dividend payments, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future.  In addition, our board of directors recently determined to suspend the dividend on our Series A Preferred Stock and Series B Preferred Stock, beginning with the three-month period ending March 31, 2019. We currently intend to retain all future earnings otherwise payable as common and, potentially, preferred dividends to fund our development and other business activities. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors may deem relevant. Covenants contained in the Credit Agreement, future credit facilities we may enter into, our indentures and the certificates of designations for our preferred stock restrict our ability to pay dividends on our common stock and could in the future restrict our ability to pay dividends on our preferred stock. In addition, the DGCL permits payment of dividends only out of a corporation’s surplus, which is defined as the excess of net assets (total assets less total liabilities) over a corporation’s capital as determined under the DGCL. If commodity prices remain at the depressed levels to which they declined during the fourth quarter of 2018, the value of our net assets will consequently remain depressed and our ability to lawfully declare and pay dividends will decline. Therefore, investors seeking cash dividends should not purchase our common stock or preferred stock.

Investors in our common stock and Preferred Stock must rely on sales of their common stock and Preferred Stock after price appreciation, which may never occur, as the only way to realize a return on their investment. However, our common stock price experienced a decline from a high closing price of $5.99 per share on January 12, 2018 to a low closing price of $0.25 per share on December 27, 2018, ending the year at $0.27 per share on December 31, 2018, and trading in our common stock has been suspended on the NYSE and our common stock is subject to NYSE delisting proceedings. See “—Trading in our common stock on the NYSE was suspended on February 20, 2019, and the NYSE has notified us that our common stock is subject to delisting proceedings. At this time, we expect that the NYSE could file a Form 25 to delist our common stock as early as March 7, 2019. Our common stock is quoted only in the over-the-counter market, which could negatively affect our stock price and liquidity.” Although the Preferred Stock has a $50.00 per share liquidation preference, it is unlikely the Preferred Stock (or our common stock) would receive any distributions upon our dissolution or liquidation. Consequently, our investors’ abilities to realize returns in their respective investments will be significantly constrained.

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

Hydraulic fracturing is an 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. Hydraulic fracturing is generally exempt from federal regulation, and thus the process is typically regulated by state agencies. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Underground Injection Control or UIC Program. In Texas, Louisiana and Mississippi, where we maintain acreage, the EPA is encouraging state programs to review and consider EPA guidance in these areas.

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

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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. The above standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. 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. 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 require the public disclosure of chemicals used in the hydraulic fracturing process, and 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. These proceedings or regulations 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 or tight formations, increase our costs of compliance and doing business and make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings.

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, 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 business, financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if additional federal, state and/or local laws are enacted. Please read "Item 1. Business – Environmental Matters and Regulation" for a description of the laws and regulations governing hydraulic fracturing.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and natural gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, on October 28, 2014, the Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and natural gas waste 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. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Commission has used this authority to deny permits for waste disposal wells.

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We dispose of large volumes of produced water gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by owned disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

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

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

In addition, the operations of the third parties on whom we rely for gathering and transportation services are also subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations. Please read "Item 1. Business—Environmental Matters and Regulation" for a description of the laws and regulations that affect the third parties on whom we rely.

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

In recent years, federal, state and local governments have taken steps to reduce emissions of 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.

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

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 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. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

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

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

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There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict and joint and several liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non compliance with environmental laws and regulations or for personal injury or property or natural resource damages. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition and results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our competitive position, business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance. Please read "Item 1. Business—Environmental Matters and Regulation" for more information.

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

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

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including (i) a rule, which we refer to as the "Mandatory Clearing Rule," requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the "End User Exception," establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the "Margin Rule," setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the "Non-Financial End User Exception;" (ii) rules, which we refer to as "Stay Rules," imposing limits on default rights on counterparties under swaps with financial institutions that are regulated by certain of the Prudential Regulators; and (iii) a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits on energy derivatives. On multiple occasions, most recently in December 2016, the CFTC proposed but did not adopt other position limit rules on energy derivatives. Such proposed rules have included exemptions from the position limits for swaps that constitute "bona fide hedging positions" within the definition of such term under such proposed rules, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of such proposed rules. It is not known whether the CFTC will adopt a rule which we refer to as a “Position Limit Rule” imposing position limits on energy derivatives or, if such a rule is adopted, whether such rule will include an exemption for “bona fide hedging positions.” Nor is it known if our hedging activities will constitute “bona fide hedging positions” under any such Position Limit Rule. In addition, in October of 2018, certain of the Prudential Regulators proposed rules, which we refer to as “Standardized Approach Rules,” which would require financial institutions regulated by such Prudential Regulators to change how they calculate exposure to swaps for purposes of determining capital requirements applicable to such financial institutions. It is not known whether such Prudential Regulators will adopt the Standardized Approach Rules, nor is it known how the adoption of such rules would affect the capital requirements applicable to our swap counterparties.

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We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate and we qualify for the Non-Financial End User Exception and will not be required to post margin under the Margin Rule, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties are subject to mandatory clearing of swaps of covered types (currently only certain interest rate and credit default swaps) in connection with their hedging activities with parties who do not qualify for the End User Exception and, depending on the scope of the their swap activities (combined with the swap activities of their affiliates) and the swap activities of their counterparties (combined with the swap activities of their affiliates) either already are or will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. The Stay Rules restricting our exercise of default rights related, directly or indirectly, to affiliates of our swap counterparties that are subject to regulation by certain of the Prudential Regulators entering into insolvency proceedings, will not become applicable to us until January 1, 2020. However, most if not all of our hedge counterparties became subject to such rules on January 1, 2019. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as “Foreign Regulations” which may apply to our transactions with counterparties subject to such Foreign Regulations. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that a Position Limit Rule and the Standardized Approach Rules are ultimately effected, such rules could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Tax laws and regulations may change over time, including the elimination of federal income tax deductions currently available with respect to oil and natural gas exploration and development.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions at the time that the filings were made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws and regulations, it could have a material adverse effect on our business and financial condition.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”) that significantly reforms the Code. The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate; (ii) repeals the corporate alternative minimum tax; (iii) eliminates the deduction for certain domestic production activities; (iv) imposes new limitations on the utilization of NOLs, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and natural gas companies. The Tax Act is complex and far-reaching and due to additional guidance that continues to be issued, we cannot predict with certainty the resulting impact its enactment will have on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations or assumptions could have an adverse effect on our business, results of operations, and financial condition.

In past years, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including, (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current expensing of intangible drilling and development costs; and (iii) an extension of

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the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could have a material adverse effect on our business, financial condition and results of operations by increasing the after tax costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

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

Provisions in our restated certificate of incorporation and amended and restated bylaws may delay or prevent an acquisition of us. These provisions may also frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, who are responsible for appointing the members of our management team. Furthermore, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the DGCL, which prohibits, with some exceptions, stockholders owning in excess of 15% of our outstanding voting stock from merging or combining with us.

In addition, the Company entered into the Rights Plan on July 28, 2015, and on July 27, 2018, the Company extended the term of the Rights Plan to July 26, 2021. Although not intended for this purpose, the Rights Plan has an anti-takeover effect. The Rights Plan is designed to preserve stockholder value and the value of our NOLs by acting as a deterrent to any person acquiring beneficial ownership of 4.9% or more of the Company's outstanding common stock without the approval of our board of directors. For more information on possible risks associated with our rights plan, please see "—We have extended the term of our net operating loss carryforwards ("NOLs") Rights Plan, which may discourage the acquisition and sale of large blocks of our common stock and may result in significant dilution for certain stockholders."

Finally, our amended and restated bylaws establish advance notice requirements for nominations for election to our board of directors and for proposing matters that can be acted upon at stockholder meetings. Although we believe these provisions together provide an opportunity to receive higher bids by requiring potential acquirers to negotiate with our board of directors, they would apply even if an offer to acquire us may be considered beneficial by some stockholders.

We are subject to legal proceedings and legal compliance risks.

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

Information regarding recent material litigation is discussed in more detail below in "Item 3. Legal Proceedings" and in "Item 8. Financial Statements and Supplementary Data — Note 15, Commitments and Contingencies."

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

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

· labor, tax, employee benefit, indemnification and other matters arising under agreements with SOG;

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· employee recruiting and retention, particularly if we engage in restructuring or recapitalization transactions;

· business opportunities that may be attractive to both members of the Sanchez Group and us; and

· business transactions that we enter into with members of the Sanchez Group.

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

Finally, in connection with our initial public offering ("IPO"), we entered into several agreements with members of the Sanchez Group. In addition, at the closing of the Comanche Acquisition, we entered into management services agreements with SOG for it to perform various management service functions for SN UnSub and Blackstone and/or their affiliates. These agreements were made in the context of a related party transaction. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties.

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

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

· members of the Sanchez Group are free to compete with us in any activity or line of business;

· we do not have any interest or expectancy in any business opportunity, transaction or other matter in which members of the Sanchez Group engage or seek to engage merely because we engage in the same or similar lines of business;

· to the fullest extent permitted by law, members of the Sanchez Group will have no duty to communicate their knowledge of, or offer, any potential business opportunity, transaction or other matter to us, and members of the Sanchez Group are free to pursue or acquire such business opportunity, transaction or other matter for themselves or direct the business opportunity, transaction or other matter to its affiliates; and

· if any director or officer of any member of the Sanchez Group who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that business opportunity to us, and will be permitted to communicate or offer that business opportunity to such member of the Sanchez Group and that director or officer will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the business opportunity or (2) acted in bad faith or in a manner inconsistent with our best interests or those of our stockholders.

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

Certain services required by us for the operation of our business, including general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, financial and accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals, are provided by SOG pursuant to the Services Agreement. The services provided under the Services Agreement commenced on the date that the IPO closed and had an initial term of five years. The term automatically extends for additional 12 month periods and is terminable by either party at any time upon 180 days' written notice. See "Corporate Governance—Compensation Committee" in the proxy statement for the 2018 annual meeting of stockholders. While these services are being provided to us by SOG, our operational flexibility to modify or implement changes with respect to such services or the amounts we pay for them is limited. After the expiration or termination of this agreement, we may not be able to replace these services or enter into appropriate third party agreements on terms and conditions, including cost, comparable to those that we will receive from SOG under our agreements with SOG. Furthermore, during the term of the Services Agreement, we or SOG may not be able to retain, attract or replace key SOG personnel, particularly if we engage in restructuring or recapitalization transactions.

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

Sector cost inflation could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and third-party oilfield materials, service and supply costs are also subject to supply and demand dynamics. During periods of decreasing levels of industry exploration and production, such as occurred in 2015 and 2016 and in the fourth quarter of 2018, the demand for, and cost of, drilling rigs and oilfield services decreases. Conversely, during periods of increasing levels of industry activity, the demand for, and cost of, drilling rigs and oilfield services increases.

In the event of robust commodity price recovery, we expect industry exploration and production activities to increase, resulting in higher demand for oilfield services and supplies and concurrent sector price inflation. In addition, the costs of such items could increase and their availability may become limited, particularly in basins of relatively higher activity.

A portion of our total outstanding shares is held by members of the Sanchez Group and may be sold into the market at any time. In addition, Blackstone and GSO (or their affiliates) received a substantial number of our securities in connection with the Comanche Acquisition which they may also sell into the market at their discretion, subject to certain limitations. Such sale transactions could cause the market price of our common stock to drop significantly, even if our business is doing well.

As of February 26, 2019, members of the Sanchez Group owned, in the aggregate, approximately 12.8% of our outstanding common stock. These shares are generally eligible for resale in the public markets, subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act, if then applicable. In addition, at the closing of the Comanche Acquisition, we issued approximately 1.5 million shares of common stock to GSO and warrants to purchase approximately 1.9 million and 6.5 million shares of common stock, at an exercise price of $10.00 per share, to GSO and three affiliates of Blackstone, respectively, resulting in GSO and such Blackstone affiliates owning approximately 4.1% and 6.8% of our common stock, respectively, assuming that the warrants were fully exercised as of February 26, 2019. Following the conclusion of a two-year lockup period which ended on March 1, 2019, shares of common stock issued pursuant to these warrants are eligible for resale in the public markets, subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act, if then applicable. In addition, under certain circumstances, members of the Sanchez Group, GSO and such Blackstone affiliates have the right to require us to register the resale of their shares. Moreover, we have registered all of the shares of our common stock that we may issue under our equity incentive plans and there were an additional 6,103,130 shares available for future issuance to our directors, officers and employees and consultants of the Sanchez Group as restricted stock or stock option awards pursuant to our Third Amended and Restated 2011 Long Term Incentive Plan (the “LTIP”) as of December 31, 2018. These shares can be freely sold in the public market upon issuance unless, pursuant to their terms, these stock awards have transfer restrictions attached to them or are held by our affiliates, in which event such shares may be sold subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act, if then applicable. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

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## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

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

## Item 3. Legal Proceedings

The information required by this Item is set forth in "Item 8. Financial Statements and Supplementary Data —Note 15, Commitments and Contingencies."

## Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Market for Registrant's Common Equity. Shares of our common stock were listed for trading on the NYSE during 2018 under the symbol "SN." Trading of the shares of our common stock on the NYSE was suspended at the market opening on February 20, 2019. At this time, the Company expects that the NYSE could file a Form 25 to delist the Common Stock as early as March 7, 2019, following the conclusion of a 10 business-day review and appeal period. Under Rule 12d2-2(d)(1) under the Exchange Act, an application on Form 25 to strike a class of securities from listing on a national securities exchange will be effective 10 days after the filing of the Form 25.

OTC Quotations. As described herein, our common stock is currently quoted on the OTC Pink under the symbol "SNEC."

Pursuant to Rule 802.01C of the NYSE LCM ("Rule 802.01C"), a company will be considered to be below compliance standards if the average closing price of a security as reported on the consolidated tape is less than $1.00 over a consecutive 30 trading-day period. In addition, pursuant to Rule 802.01B of the NYSE LCM ("Rule 802.01B"), a company will be considered to be below compliance standards if the average market capitalization is less than $50 million over a consecutive 30 trading-day period, unless at the same time the company's total shareholders' equity is equal to or more than $50 million.

On December 21, 2018, the Company was notified in writing by the NYSE that the decline in the Company's average share price had caused the Company to be out of compliance with Rule 802.01C. In accordance with applicable NYSE procedures, the Company notified the NYSE of its intent to pursue actions to meet the minimum average share price requirement and restore its compliance with the relevant standards required in Rule 802.01C within the six-month period allowed by the NYSE.

Also as previously disclosed, on January 3, 2019, the Company received written notice from the NYSE that the Company's total market capitalization was out of compliance with Rule 802.01B of the NYSE LCM, which requires that a company maintain an average market capitalization of at least $50 million over a period of 30 consecutive trading days, unless at the same time the company's total stockholders' equity is equal to or greater than $50 million. In accordance with applicable NYSE procedures pertaining to non-compliance due to low market capitalization, the Company had until February 19, 2019 to submit a plan to meet the minimum market capitalization requirement within 18 months and restore its compliance with the NYSE continued listing standards.

The Company did not submit a plan of compliance within the required timeframe that, if accepted by the NYSE, would have allowed our common stock to remain on the NYSE for a period of 18 months in order for us to bring the Company into conformity with the Rule 802.01B market capitalization standard (subject to compliance with the NYSE's other continued listing standards and continued NYSE review of our progress). On February 20, 2019, the Company received a written notice from the NYSE that, based on the foregoing, our common stock was subject to delisting proceedings. Although the NYSE LCM provides the Company limited rights to seek a review of the NYSE's determination, the Company has elected not to seek any such review or otherwise appeal the NYSE's determination. Trading in the Company's common stock was suspended at the market opening on February 20, 2019. At this time, the Company expects that the NYSE could file a Form 25 to delist the Common Stock as early as March 7, 2019, following the conclusion of the 10 business-day review and appeal period. Under Rule 12d2-2(d)(1) under the Exchange Act, an application on Form 25 to strike a class of securities from listing on a national securities exchange will be effective 10 days after the filing of the Form 25.

Our common stock is currently quoted on the OTC Pink market (OTC Pink: SNEC), although there is no assurance that an active market in the common stock will develop. Securities quoted in the over-the-counter markets are not considered to be traded on a national exchange. Even if the common stock remains quoted on the OTC Pink, the delisting of our common stock from the NYSE could negatively impact the Company, as it will likely reduce the liquidity and market price of the common stock; reduce the number of investors willing to hold or acquire the common

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stock; negatively impact the Company's ability to access equity markets and obtain financing; and impair the Company's ability to provide equity incentives.

Holders. The number of holders of record of our common stock was approximately 174 on February 26, 2019, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

Securities Authorized for Issuance Under Equity Compensation Plans. The following table sets forth certain information as of December 31, 2018 regarding the LTIP. The LTIP was approved by our stockholders on May 24, 2016, which increased the number of shares of our common stock available for incentive awards pursuant to the prior program, which was approved by our stockholders on May 21, 2015.

| Plan Category: | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | (b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) | |
|---|---|---|---|---|
| Equity Compensation Plans Approved by Stockholders | — | N/A | 6,103,130 | (1) |
| Equity Compensation Plans Not Approved by Stockholders | N/A | N/A | N/A | |
| Total | — | — | 6,103,130 | |

(1)The maximum number of shares that may be delivered pursuant to the LTIP is limited to 17,239,790 shares plus an automatic increase equal to the lesser of (A) 15% of such issuance of additional shares of common stock and (B) such lesser number of shares of common stock as determined by our board of directors and compensation committee; provided, however, that shares withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP.

Recent Sales of Unregistered Securities. All sales of unregistered securities within the last fiscal year have been previously reported in our Quarterly Reports on Form 10-Q and/or Current Reports on Form 8-K.

Repurchases of Equity Securities. Neither we nor any "affiliated purchaser" repurchased any of our equity securities in the quarter ended December 31, 2018.

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Comparative Stock Performance

The performance graph below compares the cumulative total stockholder return for our common stock to that of the Standard and Poor's, or S&P, 500 Index and the S&P 500 Oil & Gas Exploration and Production Index for the period from December 31, 2013 to December 31, 2018. "Cumulative total return" means the change in share price during the measurement period divided by the share price at the beginning of the measurement period. The graph assumes an investment of $100 was made in the Company's common stock and in each of the S&P 500 Index and the S&P 500 Oil & Gas Exploration and Production Index at the closing market price on December 31, 2013.

COMPARISON OF CUMULATIVE TOTAL RETURN

AMONG SANCHEZ ENERGY CORPORATION, THE S&P 500 INDEX,

AND THE S&P 500 OIL & GAS EXPLORATION AND PRODUCTION INDEX

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

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

Item 6. Selected Financial Data

The selected financial data table below shows our historical consolidated financial data as of and for each of the five years in the period ended December 31, 2018. The selected financial data is derived from our audited historical financial statements.

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| | (in thousands, except per share amounts) | | | | |
| REVENUES: | | | | | |
| Oil sales | $ 623,999 | $ 400,045 | $ 241,766 | $ 307,971 | $ 538,887 |
| Natural gas liquids sales | 232,085 | 171,139 | 81,744 | 69,011 | 66,989 |
| Natural gas sales | 175,117 | 169,147 | 107,816 | 98,797 | 60,188 |
| Sales and marketing revenues | 25,713 | — | — | — | — |
| Total revenues | 1,056,914 | 740,331 | 431,326 | 475,779 | 666,064 |
| OPERATING COSTS AND EXPENSES: | | | | | |
| Oil and natural gas production expenses | 305,515 | 244,461 | 155,660 | 154,672 | 93,581 |
| Production and ad valorem taxes | 56,462 | 36,615 | 19,633 | 26,870 | 37,787 |
| Exploration expenses | 3,295 | 5,755 | 403 | 1,982 | 4,238 |
| Sales and marketing expenses | 23,832 | — | — | — | — |
| Depreciation, depletion, amortization and accretion | 262,481 | 177,078 | 147,485 | 264,379 | 282,193 |
| Impairment of oil and natural gas properties | 14,386 | 39,574 | 47,381 | 723,971 | 1,060,328 |
| General and administrative expenses (1) | 98,002 | 144,401 | 110,081 | 74,160 | 63,692 |
| Total operating costs and expenses | 763,973 | 647,884 | 480,643 | 1,246,034 | 1,541,819 |
| Operating income (loss) | 292,941 | 92,447 | (49,317) | (770,255) | (875,755) |
| Other income (expense): | | | | | |
| Interest income | 4,351 | 836 | 856 | 442 | 193 |
| Other income (expense) | (8,001) | 11,102 | 134 | (2,605) | 96 |
| Gain on disposal of assets | 1,528 | 81,955 | 85,322 | — | — |
| Interest expense | (177,858) | (140,163) | (126,973) | (126,399) | (89,800) |
| Earnings from equity investments | — | 779 | 3,466 | — | — |
| Net gains (losses) on commodity derivatives | (27,756) | (6,100) | (53,149) | 172,886 | 137,205 |
| Total other income (expense) | (207,736) | (51,591) | (90,344) | 44,324 | 47,694 |
| Income (loss) before income taxes | 85,205 | 40,856 | (139,661) | (725,931) | (828,061) |
| Income tax benefit (expense) | — | 2,336 | (1,825) | (158) | — |
| Net income (loss) | 85,205 | 43,192 | (141,486) | (726,089) | (828,061) |
| Less: | | | | | |
| Preferred stock dividends | (15,948) | (15,948) | (15,948) | (16,008) | (33,590) |
| Preferred unit dividends and distributions | (47,408) | (44,259) | — | — | — |
| Preferred unit amortization | (25,316) | (18,039) | — | — | — |

| | | | | | |
|---|---|---|---|---|---|
| Net income allocable to participating securities(2)(3) | — | — | — | — | — |
| Net loss attributable to common stockholders | $ (3,467) | $ (35,054) | $ (157,434) | $ (742,097) | $ (861,651) |
| Net loss per common share - basic and diluted | $ (0.04) | $ (0.46) | $ (2.67) | $ (12.97) | $ (16.46) |
| Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted (4) | 81,764 | 75,608 | 58,900 | 57,229 | 52,338 |

(1)Includes non-cash, stock based compensation expense of $0.8 million, $22.9 million, $25.0 million, $14.8 million and $12.8 million for the years ended December 31, 2018, 2017, 2016, 2015 and 2014, respectively. Also includes acquisition and divestiture costs of $0.8 million, $30.5 million, $8.4 million, $3.8 million and $1.8 million for the years ended December 31, 2018, 2017, 2016, 2015 and 2014, respectively.

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

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(3)For the years ended December 31, 2018, 2017, 2016, 2015 and 2014 no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses.

(4)The year ended December 31, 2018 excludes 2,540,922 shares of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted loss per common share as these shares were anti-dilutive. The year ended December 31, 2017 excludes 2,755,893 shares of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock and 100,000 contingently issuable shares from the calculation of the denominator for diluted earnings per common share as these shares were anti dilutive. The year ended December 31, 2016 excludes 2,113,462 shares of weighted average restricted stock and 12,554,481 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The year ended December 31, 2015 excludes 2,663,010 shares of weighted average restricted stock and 12,529,314 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The year ended December 31, 2014 excludes 1,732,888 shares of weighted average restricted stock and 13,527,738 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti dilutive.

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| | (in thousands) | | | | |
| Balance Sheet Data: | | | | | |
| Current assets | $ 372,981 | $ 350,798 | $ 562,805 | $ 666,618 | $ 681,754 |
| Total assets | $ 2,819,960 | $ 2,470,635 | $ 1,332,211 | $ 1,440,669 | $ 2,162,146 |
| Current liabilities | $ 348,299 | 462,528 | 185,904 | 176,413 | 268,956 |
| Long term debt, net of premium, discount and debt issuance costs | $ 2,395,408 | $ 1,930,683 | $ 1,712,767 | $ 1,705,927 | $ 1,698,095 |
| Total liabilities | $ 2,811,655 | 2,512,263 | 2,016,194 | 2,000,153 | 1,994,413 |
| Total stockholders' equity (deficit) | $ (444,523) | $ (469,140) | $ (683,982) | $ (559,483) | $ 167,735 |

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| | (in thousands) | | | | |
| Cash Flow Data: | | | | | |
| Net cash provided by operating activities | $ 265,974 | $ 292,089 | $ 182,754 | $ 270,576 | $ 411,714 |
| | $ (615,540) | $ (1,382,800) | $ (108,234) | $ (292,349) | $ (1,357,026) |

| | | | | | |
|---|---|---|---|---|---|
| Net cash used in investing activities | | | | | |
| Net cash provided by (used in) financing activities | $ 362,745 | $ 773,228 | $ (7,651) | $ (16,893) | $ 1,265,495 |

Non GAAP Financial Measures

PV-10

PV 10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). PV 10 is a computation of the Standardized Measure on a pre tax basis. PV 10 is equal to the

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Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV 10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV 10, however, is not a substitute for the Standardized Measure. Our PV 10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV 10 to the Standardized Measure at December 31, 2018 for our proved reserves (in millions):

| | Proved Reserves |
|---|---|
| PV-10 | $ 2,608.0 |
| Present value of future income taxes discounted at 10% | 133.3 |
| Standardized Measure (1) | $ 2,474.8 |

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

## Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes set forth in “Item 8. Financial Statements and Supplementary Data,” our consolidated financial data set forth in “Item 6. Selected Financial Data” and the risk factors identified in “Item 1A. Risk Factors” of this Annual Report on Form 10 K.

Our estimated proved reserve information as of December 31, 2018 contained in this Annual Report on Form 10-K is based on a report prepared by Ryder Scott, our independent reserve engineers.

Certain items in our discussion below are forward-looking statements. These forward looking statements involve risks and uncertainties. A number of factors could cause actual results to differ materially from those implied or expressed in such forward-looking statements. Please see "Cautionary Note Regarding Forward-Looking Statements."

Business Overview

Sanchez Energy, 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 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

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

Basis of Presentation

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

Our Properties

We and our predecessor entities have a long history in the Eagle Ford Shale, where, 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, approximately 987 of these drilling locations represented PUDs and were developed using existing geologic and engineering data identified by our management team. Although these approximate 3,403 gross additional non-proved locations are 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 estimations desired 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 limitation in the number of locations which 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. 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.

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

Recent Developments

2019 Capital Program

The Company has set its 2019 capital budget at a range of $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.

Outlook

We and other companies in our industry face significant risks related to business operations, the prices we receive for our production, competition for employees and capital, and other factors which could materially impact our results of operations and financial condition. During recent months, our oil and natural gas production has fallen short of expectations due to a number of contributing factors, including the impacts of certain activities designed and implemented to evaluate various reservoir stimulation and hydrocarbon flowback strategies and appraisal initiatives to

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assess the productivity of certain horizons in the Eagle Ford Shale, in consultation with certain of our working interest partners, and extreme weather events in South Texas which led to extended production shut-ins and delays in bringing new production online. We have taken responsive actions to address these operational challenges and anticipate a return to more predictable production levels. Additionally, in response to a prolonged period of commodity price volatility and to meet certain minimum hedging requirements in our debt agreements, we took advantage of market opportunities in recent years to hedge a significant percentage of our oil and natural gas production for 2018 at prices of approximately $52 per Bbl for oil and $3 per MMBtu for natural gas. However, oil prices recovered to substantially higher levels during the first three quarters of 2018 and our hedge position limited the positive impact we received from the more favorable market prices. We are hedged to a lower extent in 2019 and beyond. We believe that a recovery in our operational performance, as well as stronger commodity prices, could improve our overall financial position.

Although commodity and capital markets showed signs of improvement, oil prices experienced a significant decline in the fourth quarter of 2018. As a result, we continue to manage our business for the potential of ongoing commodity price volatility. This volatility has significantly influenced our industry and operating environment in the past, and we believe it may again in the future. We face continuing uncertainty with respect to the demand for our products, commodity prices, service availability and costs, and our ability to fund capital projects, along with significant challenges associated with our financial position. In November 2018, we engaged Moelis & Company LLC (“Moelis”) as financial advisor to explore strategic alternatives to strengthen our balance sheet and maximize the value of the Company. We are currently reviewing our alternatives, and we may adopt strategies that include actions such as a refinancing or restructuring of our indebtedness or capital structure, reducing or delaying capital investments, selling non-core assets or seeking to raise additional capital through debt or equity financing.

We currently expect that the Company’s cash flows and cash on hand will be sufficient to fund our anticipated 2019 operating needs, debt service obligations, capital expenditures, and commitments and contingencies. However, if commodity prices decline further, we may be unable to meet our remaining 2019 operating needs, debt service obligations, capital expenditures and commitments and contingencies. We continuously evaluate our current and projected capital spending, operating activities and funding requirements, with consideration of realized commodity prices and the results of our operations and may make further adjustments to our capital expenditures and related financing plans as warranted. In addition, we  periodically review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

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Results of Operations

Net Production and Revenues from Production

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

| | Year Ended December 31, | | | Increase (Decrease) 2018 vs 2017 | | 2017 vs 2016 | |
|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | $ | % | $ | % |
| Net Production: | | | | | | | |
| Oil (MBbls) | 9,655 | 8,217 | 6,370 | 1,438 | 18 % | 1,847 | 29 % |
| Natural gas liquids (MBbls) | 9,936 | 8,342 | 5,960 | 1,594 | 19 % | 2,382 | 40 % |
| Natural gas (MMcf) | 55,330 | 54,651 | 43,189 | 679 | 1 % | 11,462 | 27 % |
| Total oil equivalent (MBoe) | 28,813 | 25,667 | 19,529 | 3,146 | 12 % | 6,138 | 31 % |
| Average Sales Price Excluding Derivatives(1): | | | | | | | |
| Oil ($ per Bbl) | $ 64.63 | $ 48.69 | $ 37.95 | $ 15.94 | 33 % | $ 10.74 | 28 % |
| Natural gas liquids ($ per Bbl) | 23.36 | 20.52 | 13.72 | 2.84 | 14 % | 6.80 | 50 % |
| Natural gas ($ per Mcf) | 3.16 | 3.10 | 2.50 | 0.06 | 2 % | 0.60 | 24 % |
| Oil equivalent ($ per Boe) | $ 35.79 | $ 28.84 | $ 22.09 | $ 6.95 | 24 % | $ 6.75 | 31 % |
| Average Sales Price Including Derivatives(2): | | | | | | | |
| Oil ($ per Bbl) | $ 54.26 | $ 50.12 | $ 55.37 | $ 4.14 | 8 % | $ (5.25) | (9) % |
| Natural gas liquids ($ per Bbl) | 23.36 | 20.52 | 13.72 | 2.84 | 14 % | 6.80 | 50 % |
| Natural gas ($ per Mcf) | 3.11 | 3.12 | 3.07 | (0.01) | (0) % | 0.05 | 2 % |
| Oil equivalent ($ per Boe) | $ 32.21 | $ 29.36 | $ 29.03 | $ 2.85 | 10 % | $ 0.33 | 1 % |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Revenues from Production(1)(3): | | | | | | | | |
| Oil sales | $ 623,999 | $ 400,045 | $ 241,766 | $ 223,954 | 56 | % | $ 158,279 | 65 % |
| Natural gas liquids sales | 232,085 | 171,139 | 81,744 | 60,946 | 36 | % | 89,395 | 109 % |
| Natural gas sales | 175,117 | 169,147 | 107,816 | 5,970 | 4 | % | 61,331 | 57 % |
| Total revenues from production | $ 1,031,201 | $ 740,331 | $ 431,326 | $ 290,870 | 39 | % | $ 309,005 | 72 % |

(1) Excludes the realized impact of derivative instrument settlements.

(2) Includes the realized impact of derivative instrument settlements.

(3) Excludes revenues related to sales and marketing activities.

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Net Production. Net production increased from 25,667 MBoe in 2017 to 28,813 MBoe in 2018 primarily due to the addition of the Comanche Assets and an increase in Catarina wells brought online compared to the comparable period of 2017. The number of gross wells producing at year end and the production for the periods were as follows:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2018 | | 2017 | | 2016 | |
| | # Wells | MBoe | # Wells | MBoe | # Wells | MBoe |
| Comanche | 1,742 | 11,963 | 1,582 | 9,089 | — | — |
| Catarina | 460 | 15,043 | 389 | 14,389 | 333 | 15,847 |
| Palmetto | 82 | 161 | 84 | 346 | 76 | 511 |
| Maverick | 68 | 1,551 | 63 | 1,477 | 36 | 888 |
| Cotulla | — | — | — | 30 | 49 | 1,279 |
| Marquis | — | — | — | 304 | 103 | 958 |
| TMS / Other | 46 | 95 | 47 | 32 | 14 | 46 |
| Total | 2,398 | 28,813 | 2,165 | 25,667 | 611 | 19,529 |

In 2018, 34% of our production was oil, 34% was NGLs and 32% was natural gas compared to 2017 production that was 32% oil, 33% NGLs and 35% natural gas. In 2016, 33% of our production was oil, 30% NGLs and 37% natural gas. The production mix has become more NGL-weighted in the current period primarily from additional wells online and new wells at Catarina in areas with a higher NGL concentration compared to the comparable period of 2017.

Revenues from Production. Sales revenue for oil, NGLs and natural gas totaled approximately $1,031.2 million, $740.3 million, and $431.3 million for the years ended December 31, 2018, 2017 and 2016, respectively. Sales revenue for oil, NGLs and natural gas for the year ended December 31, 2018 increased $224.0 million, $61.0 million and $6.0 million, respectively, as compared to the year ended December 31, 2017. The increase in sales revenue is primarily attributable to increased production related to the Comanche Acquisition, completed in March 2017, in addition to higher commodity prices.

Sales and Marketing Revenues. During 2018, we entered into commodity purchase transactions with certain third parties and then subsequently sold the purchased commodity as separate revenue streams. We believe an opportunity exists, from time to time, to participate in additional economic benefits and operational efficiencies in support of our upstream activities by purchasing and reselling production from others, to a limited extent, in order to utilize existing firm transportation arrangements. The Company recorded sales and marketing revenues of $25.7 million during the year ended December 31, 2018 associated with these transactions.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our revenues from production from the year ended December 31, 2017 to the year ended

December 31, 2018 (in thousands, except average sales price). The increase in revenue from the year ended December

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31, 2017 to the year ended December 31, 2018 is primarily attributable to the increase in commodity prices and the increase in production volume.

| | Production Volume | | | 2017 | |
|---|---|---|---|---|---|
| | 2018 | 2017 | Difference | Average Sales Price | Revenue Increase from Production |
| Oil (MBbls) | 9,655 | 8,217 | 1,438 | $ 48.69 | $ 70,033 |
| Natural gas liquids (MBbls) | 9,936 | 8,342 | 1,594 | $ 20.52 | $ 32,687 |
| Natural gas (MMcf) | 55,330 | 54,651 | 679 | $ 3.10 | $ 2,104 |
| Total oil equivalent (MBoe) | 28,813 | 25,667 | 3,146 | $ 28.84 | $ 104,824 |

| | Average Sales Price per Unit | | | 2018 | |
|---|---|---|---|---|---|
| | 2018 | 2017 | Difference | Production Volume | Revenue Increase from Price |
| Oil (MBbls) | $ 64.63 | $ 48.69 | $ 15.94 | 9,655 | $ 153,921 |
| Natural gas liquids (MBbls) | $ 23.36 | $ 20.52 | $ 2.84 | 9,936 | $ 28,259 |
| Natural gas (MMcf) | $ 3.16 | $ 3.10 | $ 0.06 | 55,330 | $ 3,866 |
| Total oil equivalent (MBoe) | $ 35.79 | $ 28.84 | $ 6.95 | 28,813 | $ 186,046 |

Additionally, a 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the year ended December 31, 2018 by approximately $103.1 million.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our revenues from the year ended December 31, 2016 to the year ended December 31, 2017 (in thousands, except average sales price):

| | Production Volume | | | 2016 | |
|---|---|---|---|---|---|
| | 2017 | 2016 | Difference | Average Sales Price | Revenue Increase from Production |
| Oil (MBbls) | 8,217 | 6,370 | 1,847 | $ 37.95 | $ 70,063 |
| Natural gas liquids (MBbls) | 8,342 | 5,960 | 2,382 | $ 13.72 | $ 32,668 |
| Natural gas (MMcf) | 54,651 | 43,189 | 11,462 | $ 2.50 | $ 28,610 |
| Total oil equivalent (MBoe) | 25,667 | 19,529 | 6,138 | $ 22.09 | $ 131,341 |

2017

| | Average Sales Price per Unit | | | Production | Revenue Increase |
|---|---|---|---|---|---|
| | 2017 | 2016 | Difference | Volume | from Price |
| Oil (MBbls) | $ 48.69 | $ 37.95 | $ 10.74 | 8,217 | $ 88,216 |
| Natural gas liquids (MBbls) | $ 20.52 | $ 13.72 | $ 6.80 | 8,342 | $ 56,727 |
| Natural gas (MMcf) | $ 3.10 | $ 2.50 | $ 0.60 | 54,651 | $ 32,721 |
| Total oil equivalent (MBoe) | $ 28.84 | $ 22.09 | $ 6.75 | 25,667 | $ $177,664 |

Additionally, a 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the year ended December 31, 2017 by approximately $74.0 million.

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Operating Costs and Expenses

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

| | Year Ended December 31, | | | Increase (Decrease) 2018 vs 2017 | | 2017 vs 2016 | |
|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | $ | % | $ | % |
| Oil and natural gas production expenses | $ 305,515 | $ 244,461 | $ 155,660 | $ 61,054 | 25 % | $ 88,801 | 57 % |
| Exploration expenses | 3,295 | 5,755 | 403 | (2,460) | (43) % | 5,352 | * |
| Sales and marketing expenses | 23,832 | — | — | 23,832 | * | — | * |
| Production and ad valorem taxes | 56,462 | 36,615 | 19,633 | 19,847 | 54 % | 16,982 | 86 % |
| Depreciation, depletion, amortization and accretion | 262,481 | 177,078 | 147,485 | 85,403 | 48 % | 29,593 | 20 % |
| Impairment of oil and natural gas properties | 14,386 | 39,574 | 47,381 | (25,188) | (64) % | (7,807) | (16) % |
| General and administrative expenses (1) | 98,002 | 144,401 | 110,081 | (46,399) | (32) % | 34,320 | 31 % |
| Total operating costs and expenses | 763,973 | 647,884 | 480,643 | 116,089 | 18 % | 167,241 | 35 % |
| | | | | | | | |
| Interest income and other income (expense) | (3,650) | 11,938 | 990 | (15,588) | (131) % | 10,948 | * |
| Gain on sale of oil and natural gas properties | 1,528 | 81,955 | 85,322 | (80,427) | (98) % | (3,367) | (4) % |
| Interest expense | (177,858) | (140,163) | (126,973) | 37,695 | (27) % | 13,190 | (10) % |
| | — | 779 | 3,466 | (779) | * | (2,687) | (78) % |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Earnings from equity investments | | | | | | | |
| Net losses on commodity derivatives | (27,756) | (6,100) | (53,149) | (21,656) | * | 47,049 | (89) % |
| Income tax benefit (expense) | — | 2,336 | (1,825) | (2,336) | * | 4,161 | * |

*Not meaningful.

(1) 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.

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Our oil and natural gas production expenses totaled $305.5 million ($10.60 per Boe) for the year ended December 31, 2018, as compared to $244.5 million ($9.52 per Boe) for the same period in 2017 and $155.7 million ($7.97 per Boe) for the same period in 2016. The increase from 2017 to 2018 is primarily attributable to the increase in operating and transportation costs incurred in the operation of our larger asset base and a higher number of producing wells brought online and acquired as part of the Comanche Acquisition in March 2017. Additionally, we increased our workover activity during 2018 as compared to 2017 and 2016. The increase in oil and natural gas production expenses per Boe was due to production expenses increasing by a higher percentage than production.

Exploration Expenses. The Company records exploration expenditures as charges against earnings for items such as exploratory dry holes, exploratory geological and geophysical costs and delay rentals. Exploration expenses totaled $3.3 million, $5.8 million and $0.4 million during the years ended December 31, 2018, 2017 and 2016, respectively. The decrease in our exploration expenses in 2018 was primarily due to a decrease in our exploratory geological and geophysical seismic costs and a decrease in our delay rentals as compared to 2017.

Sales and Marketing Expenses. During 2018, we entered into commodity purchase transactions with certain third parties and then subsequently sold the purchased commodity as separate revenue streams. The Company incurred expenses to purchase and transport the commodity of approximately $23.8 million for the year ended December 31, 2018. Please see “Sales and Marketing Revenue” above for additional information.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Ad valorem taxes are paid based upon the appraised fair market value of producing properties using an estimated discounted cash flow approach by a fixed rate established by state or local taxing authorities. Our production and ad valorem taxes totaled $56.5 million

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($1.96 per Boe), $36.6 million ($1.43 per Boe) and $19.6 million ($1.01 per Boe) for the years ended December 31, 2018, 2017 and 2016, respectively. The production tax increase from 2016 to 2018 was primarily due to the corresponding increases in production during the periods, and the increase in ad valorem taxes was due to an increase in our asset base as a result of the Comanche Acquisition completed in March 2017 and an increase in property value as a result of rising commodity prices. Our average production and ad valorem taxes per Boe increased for the year ended December 31, 2018 primarily due to the increased revenue and asset base as previously described.

Depreciation, Depletion and Amortization. Depletion, depreciation and amortization ("DD&A") expense for the year ended December 31, 2018 increased to $262.5 million ($9.11 per Boe) from $177.0 million ($6.90 per Boe) in 2017 and $147.5 million ($7.55 per Boe) in 2016. Approximately $21.7 million and $46.4 million of the increases in 2018 and 2017 expenses, respectively, resulted from higher production as a result of the Comanche Acquisition and approximately $63.8 million and $16.8 million of the increases and decreases, respectively, in expenses in 2018 and 2017, respectively, are attributable to a higher depletion rate. Please refer to "Item 8. Financial Statements and Supplementary Data —Note 2, Basis of Presentation and Summary of Significant Accounting Policies" for discussion of our DD&A methodology.

Impairment of Oil and Natural Gas Properties. During the years ended December 31, 2018 and 2016, we recorded proved property impairment of $6.6 million and $3.7 million, respectively, due to the decline of oil and natural gas prices during the periods. We did not record a proved property impairment during the year ended December 31, 2017. The impact of lower commodity prices adversely affecting proved reserve values primarily contributed to the proved property impairment. Changes in production rates, levels of reserves, future development costs and other factors will determine our actual impairment analyses in future periods. In addition, we recorded impairment of $7.8 million, $39.6 million and $43.7 million to our unproved oil and natural gas properties for the years ended December 31, 2018, 2017 and 2016, respectively. Our unproved impairment expenses for the years ended December 31, 2018 and 2016 were due to acreage expiration from changes in our development plan. Our unproved impairment for the year ended December 31, 2017 was due to a write-down of our TMS acreage to fair value due to the SR Acquisition (as defined in "Item 8. Financial Statements and Supplementary Data – Note 6, Debt.") Please refer to "Item 8. Financial Statements and Supplementary Data —Note 2, Basis of Presentation and Summary of Significant Accounting Policies" for further discussion of our impairment methodology.

General and Administrative Expenses. Our general and administrative ("G&A") expenses totaled $98.0 million ($3.40 per Boe) for the year ended December 31, 2018 compared to $144.4 million ($5.63 per Boe) and $110.1 million ($5.64 per Boe) for the same periods in 2017 and 2016, respectively. The decrease in G&A expenses from 2017 to 2018 was primarily due to a decrease in stock-based compensation, a decrease in professional fees resulting from the 2017 Comanche Acquisition and additional recovery of overhead costs during the period. Offsetting these decreases were additional consulting fees and increased employee headcount and activities associated with managing a larger public company. The increase in G&A expenses from 2016 to 2017 was primarily due to costs for additional personnel and for consulting services and increased acquisition and divestiture costs incurred during 2017 associated with the Comanche Acquisition.

We recorded non-cash stock based compensation expense (settled in common shares) of approximately $0.8 million ($0.03 per Boe), $22.9 million ($0.89 per Boe) and $25.0 million ($1.28 per Boe) for the years ended December 31, 2018, 2017 and 2016, respectively. These decreases were due primarily to a decrease in the Company's stock price from period to period offset by the increase in awards made during the year and the associated amortization recognized. The Company records stock based compensation expense for awards granted to non employees at fair value and the unvested awards are revalued each period, impacting the amortization over the remaining life of the awards.

We recorded costs associated with insignificant acquisition and divestiture activities that are included in G&A of $0.8 million ($0.03 per Boe) for the year ended December 31, 2018. Costs associated with significant acquisitions and divestiture activities included in G&A totaled approximately $30.5 million ($1.19 per Boe) for the year ended December 31, 2017 primarily attributable to the Comanche Acquisition and $8.4 million ($0.43 per Boe) for the year ended December 31, 2016 primarily attributable to the Carnero Gathering Disposition, Carnero Processing Disposition, Production Asset Transaction and Cotulla Disposition.

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Other Income (Expense). For the years ended December 31, 2018, 2017 and 2016, other income (expense) totaled ($8.0 million), $11.1 million and $0.1 million, respectively. The other expense during the year ended December 31, 2018 relates primarily to losses of $21.3 million and $0.5 million associated with the decreases in fair values of the investments in SNMP and Lonestar, respectively, as compared to a loss of $1.6 million and a de minimis loss, respectively, for the comparable period of 2017. Additionally, we incurred a gain of $1.2 million on our embedded derivatives for the year ended December 31, 2018 as compared to a loss of $1.6 million during the comparable period of 2017, and we received $9.0 million from income on Company owned equipment as compared to income of $9.4 million during the year ended December 31, 2017.

Interest Expense. For the year ended December 31, 2018, interest expense totaled $177.9 million and included $16.3 million in amortization of debt issuance costs. This is compared to the year ended December 31, 2017, for which interest expense totaled $140.2 million and included $12.6 million in amortization of debt issuance costs, and to the year ended December 31, 2016, for which interest expense totaled $127.0 million and included $7.8 million in amortization of debt issuance costs. The increase in interest expense for the year ended December 31, 2018 is primarily attributable to additional interest and debt issuance cost amortization related to the 7.25% Senior Secured Notes issued in February 2018 as well as interest on outstanding borrowings associated with the SN UnSub Credit Agreement.

Commodity Derivative Transactions. We apply mark to market accounting to our derivative contracts; therefore, the full volatility of the non cash change in fair value of our outstanding contracts is reflected in other income and expenses. During the year ended December 31, 2018, we recognized a net loss of $27.8 million on our commodity derivative contracts, which included net losses of $103.2 million associated with the settlements of commodity derivative contracts, offset by mark-to-market gains of $75.4 million on unsettled commodity derivative contracts. The mark-to-market gains were a result of the decrease in estimated future commodity prices as compared to the derivative settlement prices. The settlement losses during the period were primarily a result of increases in commodity prices from the time the positions were entered into until the time of settlement. During the year ended December 31, 2017, we recognized a net loss of $6.1 million on our commodity derivative contracts, which included net gains of $13.1 million associated with the settlements of commodity derivative contracts. During the year ended December 31, 2016, we recognized a net loss of $53.1 million on our commodity derivative contracts, which included net gains of $135.6 million associated with the settlements of commodity derivative contracts.

Income tax benefit (expense). For the year ended December 31, 2018, the Company did not record an income tax benefit or expense. Our effective tax rate for the year ended December 31, 2018 was approximately 0.0% compared to the statutory rate of 21%. The difference between the statutory rate and the Company’s effective tax rate is primarily related to a valuation allowance recorded during the period due to the Company’s uncertainty that it is more likely than not that its deferred tax assets will be realized. For the year ended December 31, 2017, we recorded income tax benefit of $2.3 million. Our effective tax rate for the year ended December 31, 2017 was (5.7)% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company’s effective tax rate is primarily related to the valuation allowance of approximately $258.1 million recorded during the period and the impact to deferred taxes for the change in the federal income tax rate of 35% to 21% of approximately $227.4 million. For the year ended December 31, 2016, the Company recorded income tax expense of $1.8 million. Our effective tax rate for the year ended December 31, 2016 was (1.3)% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company’s effective tax rate is related to the valuation allowance of approximately $46.2 million recorded during the period.

Liquidity and Capital Resources

The primary source of liquidity and capital resources to fund our development program and other obligations has been cash flow from operations, available cash on hand and proceeds from borrowings and securities issuances. Operating cash flows, however, are largely dependent on oil and natural gas prices and differentials, sales volumes and costs. Oil and natural gas prices declined significantly during the fourth quarter of 2018 and have remained low in 2019 through the present date. These lower commodity prices have negatively impacted revenues, earnings and cash flows, and sustained low oil and natural gas prices have had and will continue to have a material and adverse effect on our liquidity position and our ability to raise additional funds through financing transactions.

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As of December 31, 2018, we had approximately $197.6 million in cash and cash equivalents, $25.0 million in available borrowing capacity under the Credit Agreement, and $147.5 million in available borrowing capacity under the SN UnSub Credit Agreement, resulting in aggregate liquidity of approximately $370.1 million. For a description of the credit agreements along with the indentures covering our Senior Notes in effect as of December 31, 2018, refer to "Item 8. Financial Statements and Supplementary Data — Note 6. Debt." However, as of February 26, 2019 we had approximately $17.1 million in letters of credit outstanding under the Credit Agreement and no borrowings, resulting in less than $8 million in availability for borrowings or letters of credit. Failure to comply with certain operational covenants under the Credit Agreement or UnSub Credit Agreement could result in events of default in the future that would restrict our access to capital and/or accelerate our payment obligations. In addition, in December 2018 the borrowing base under the UnSub Credit Agreement was reduced from $380 million to $315 million and the borrowing base may be further decreased in the future.

On February 14, 2018, we issued $500 million in aggregate principal amount of the 7.25% Senior Secured Notes and amended and restated our prior revolving credit facility to, among other things, (i) reduce its size from a $350 million borrowing base with a $300 million aggregate commitment amount to a $25 million commitment to provide primarily for working capital and letters of credit; (ii) extend the maturity from 2019 to 2023; (iii) remove all material financial maintenance covenants; and (iv) provide for the continued ability to hedge. See "Item 8. Financial Statements and Supplementary Data – Note 6, Debt."

In response to the decline in oil prices and with an objective of preserving capital and maximizing our liquidity position, we have further reduced our capital budget for 2019 from a previously anticipated amount of approximately $350 million to approximately $100 million to $150 million. These levels represent a substantial reduction from our capital expenditures in 2018 by approximately $450 million to $500 million. The 2019 budget is focused on lower risk development and optimization opportunities and was prepared in order to satisfy the minimum drilling and completions activity required under our leasehold agreements to maintain our acreage positions at Catarina and Comanche, while maximizing our financial flexibility. The slowdown in development of our properties will lead to a decline in our production and possibly reserves, 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 proved undeveloped reserves to no longer be proved reserves if we are required to defer planned capital expenditures beyond 2019 due to circumstances we did not 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 are evaluating strategic alternatives that, if consummated, may provide us with additional capital beyond our operating cash flows; however, we cannot provide assurance that any of these transactions will be completed.

In November 2018, we engaged Moelis as financial advisor to explore strategic alternatives to strengthen our balance sheet and maximize the value of the Company. We are currently reviewing our alternatives, and we may adopt strategies that include actions such as a refinancing or restructuring of our indebtedness or capital structure, reducing or delaying capital investments, selling non-core assets or seeking to raise additional capital through debt or equity financing. However, our current credit rating limits our ability to access the debt capital markets and 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.  Furthermore, the recent low trading price of our common stock and our anticipated imminent delisting from the NYSE severely limit our ability to raise substantial capital in the equity markets. In addition, as part of these strategic alternatives or otherwise, we may from time to time seek to retire or purchase our outstanding debt as well as our outstanding preferred equity securities through cash purchases and/or exchanges for equity securities and/or debt securities, as applicable, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

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The Company is evaluating strategic alternatives to help provide financial stability, but no assurances can be given as to the outcome or timing of the process. We may need to seek relief under the U.S. Bankruptcy Code to restructure our current obligations under our existing outstanding debt and preferred stock instruments, and address near-term liquidity needs. 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.

With the significant reduction of our capital budget, we currently expect that the Company's cash flows and cash on hand will be sufficient to fund our anticipated 2019 operating needs, debt service obligations, capital expenditures, and commitments and contingencies. However, if commodity prices decline further, we may be unable to meet our remaining 2019 operating needs, debt service obligations, capital expenditures and commitments and contingencies.

We continuously evaluate our current and projected capital spending, operating activities and funding requirements, with consideration of realized commodity prices and the results of our operations and may make further adjustments to our capital expenditures and related financing plans as warranted. In addition, we periodically review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

Cash Flows

Our cash flows for the years ended December 31, 2018, 2017 and 2016 were as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Cash Flow Data: | | | |
| Net cash provided by operating activities | $ 265,974 | $ 292,089 | $ 182,754 |
| Net cash used in investing activities | $ (615,540) | $ (1,382,800) | $ (108,234) |
| Net cash provided by (used in) financing activities | $ 362,745 | $ 773,228 | $ (7,651) |

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $266.0 million for the year ended December 31, 2018 compared to $292.1 million and $182.8 million for the same periods in 2017 and 2016, respectively. This decrease was primarily related to increased cash payments on commodity derivative settlements.

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

Net Cash Used in Investing Activities.  Net cash flows used in investing activities totaled $615.5 million for the year ended December 31, 2018 compared to $1,382.8 million and $108.2 million for the same periods in 2017 and 2016, respectively. Capital expenditures for drilling and leasehold activities for the year ended December 31, 2018 totaled $616.2 million, primarily associated with bringing 217 gross wells online. In addition, we received $2.8 million related to post-closing adjustments for the Comanche Acquisition during the year ended December 31, 2018.

For the year ended December 31, 2017, we incurred capital expenditures for drilling and leasehold activities of $500.3 million, primarily associated with commencing completions operations on 129 drilled but uncompleted wells acquired in the Comanche Acquisition, of which 105 had been brought online as of year end. We paid a net purchase price of approximately $1,043.7 million for the Comanche Acquisition and received a total of $14.3 million for the additional closings of the Cotulla Disposition that occurred in January and April 2017 as well as adjustments on the final settlement statement in September 2017.  We received $44.0 million at the closing of the Marquis Disposition, $12.5 million for the SOII Disposition (as defined in "Item 8. Financial Statements and Supplementary Data – Note 17,

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Investments"), and an additional $105 million for the Javelina Disposition. In addition, we invested $18.6 million in other property and equipment during the year ended December 31, 2017.

For the year ended December 31, 2016, we incurred capital expenditures for drilling and leasehold activities of $312.9 million, primarily associated with bringing online 48 gross wells and expanding our acreage and asset position in the Eagle Ford Shale through leasing. We spent approximately $36.5 million towards equity method investments prior to divesting these investments as part of the Carnero Gathering Disposition and Carnero Processing Disposition for combined cash proceeds of approximately $92.5 million. In addition, we received cash of approximately $153.5 million for the Cotulla Disposition, purchased common units of SNMP for $25 million, and invested approximately $5.4 million in other assets.

Net Cash Provided by (Used in) Financing Activities. Net cash flows provided by financing activities totaled $362.7 million and $773.2 million for the years ended December 31, 2018 and 2017, respectively, and net cash flows used in financing activities totaled $7.7 million for the year ended December 31, 2016. During the year ended December 31, 2018, we issued $500 million in 7.25% Senior Secured Notes (net of discounts of $5.1 million) and had incremental borrowings of $47.5 million under the Credit Agreement. Additionally, we made repayments on the Credit Agreement of $95 million and payments on the SN UnSub Credit Agreement of $10.5 million.

In connection with the Comanche Acquisition in March 2017, we entered into the SN UnSub Credit Agreement and issued the SN UnSub Preferred Units (as defined in "Item 8. Financial Statements and Supplementary Data – Note 7, Stockholders' and Mezzanine Equity") for $500 million. From time to time, the Company has borrowed under our prior revolving credit facility and the SN UnSub Credit Agreement to make acquisitions, fund capital expenditures and provide liquidity for working capital and other general corporate purposes. As of December 31, 2017, we had outstanding borrowings of $50 million under the prior revolving credit facility and $250 million of the elected commitment amount of $300 million was available for future borrowings. Further, as of December 31, 2017, we had outstanding borrowings of $175.5 million under the SN UnSub Credit Agreement and approximately $154.5 million of the elected commitment amount of $330 million was available for future borrowings. In addition, we issued common stock for $135.9 million (net of underwriting discounts of $7.8 million). We made payments of $46.7 million for deferred financing costs associated with the SN UnSub Credit Agreement and issuance costs for the SN UnSub Preferred Units, collectively. In addition, we made payments of $1.4 million of employee taxes by withholding shares associated with stock-based compensation, which is considered a financing payment under the accounting guidance of ASU 2016-09. During the year ended December 31, 2017, we also made payments of $44.3 million for tax distributions to holders of the SN UnSub Preferred Units.

During the year ended December 31, 2016, we made payments of $4.0 million for dividends on our Series A Preferred Stock and Series B Preferred Stock, payments of approximately $1.7 million for deferred financing costs associated with an amendment to the prior revolving credit facility, and payments of approximately $1.9 million of employee taxes by withholding shares associated with stock-based compensation. In addition, we received cash of approximately $153.5 million for the Cotulla Disposition, purchased 2,272,727 common units of SNMP from SNMP for $25 million in a private placement that closed in November 2016 concurrently with SNMP's public offering of approximately 6.5 million common units, and invested approximately $5.4 million in other assets.

Commitments and Contractual Obligations

Refer to "Item 8. Financial Statements and Supplementary Data — Note 15, Commitments and Contingencies" for a description of lawsuits pending against the Company.

As of December 31, 2018, our contractual obligations included our Senior Notes (as defined in Item 8. Financial Statements and Supplementary Data — Note 6, Debt), interest expense on our Senior Notes, asset retirement obligations, rent expense for our corporate offices, lease of the Catarina midstream assets and other long term lease payments. The following table summarizes our contractual obligations as of December 31, 2018 (in thousands):

| | Less than 1 year | 1 - 3 years | 3 - 5 years | More than 5 years | Total |
|---|---|---|---|---|---|
| Senior Notes | $ — | $ 600,000 | $ 1,650,000 | $ — | $ 2,250,000 |
| SN UnSub Credit Agreement | — | — | 167,500 | — | 167,500 |
| Non-Recourse Subsidiary Term Loan | 391 | 793 | 2,619 | — | 3,803 |
| SR Credit Agreement | 304 | — | 23,187 | — | 23,491 |
| Interest expense(1) | 153,366 | 283,408 | 160,109 | — | 596,883 |
| Asset retirement obligations(2) | — | — | — | 46,175 | 46,175 |
| Office rent(3) | 6,217 | 12,749 | 13,186 | 8,468 | 40,620 |
| Operating leases of midstream assets (4) | 85,175 | 122,218 | 28,773 | — | 236,166 |
| Midstream commitments(5) | 85,765 | 156,009 | 102,303 | 164,855 | 508,932 |
| Drilling and operating equipment (6) | 19,575 | 22,555 | — | — | 42,130 |
| Other leases(7) | 903 | 1,806 | 1,353 | — | 4,062 |
| Total | $ 351,696 | $ 1,199,538 | $ 2,149,030 | $ 219,498 | $ 3,919,762 |

(1) Represents estimated interest payments that will be due under the 7.75% Notes, 6.125% Notes, 7.25% Senior Secured Notes and Non-Recourse Subsidiary Term Loan that will mature on June 15, 2021, January 15, 2023, February 15, 2023 and August 31, 2022, respectively.

(2) Amounts represent the present value of our estimate of future asset retirement obligations. As these obligations typically extend many years into the future, estimating these costs requires management to make estimates and judgments that are subject to revisions based on numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See "Item 8. Financial Statements and Supplementary Data — Note 13, Asset Retirement Obligations."

(3) Represents lease payments due for corporate office space in Houston and Carrizo Springs, Texas. The two lease agreements for Houston had terms of November 1, 2014 through March 31, 2025 and March 1, 2017 through December 31, 2025, and the lease agreement for Carrizo Springs had a term of January 1, 2017 through April 30, 2024.

(4) Represents payments due with respect to firm commitment oil and natural gas volumes under:

(i) the Gathering Agreement (as defined in "Item 8. Financial Statements and Supplementary Data — Note 10, Related Party Transactions") related to the Western Catarina Midstream Divestiture. As part of this sale, the Gathering Agreement represents an operating lease of the Catarina midstream assets. The firm commitment term under the

Gathering Agreement commenced on October 14, 2015 and will continue until October 13, 2020;

(ii) the Carnero Gathering Pipeline and the Raptor Processing Plant (as defined in "Item 8. Financial Statements and Supplementary Data — Note 17, Investments"), respectively, all owned by Carnero G&P LLC and due under the Amended Gathering Agreement and the Amended Processing Agreement (each as defined in "Item 8. Financial Statements and Supplementary Data – Note 10, Related Party Transactions"). These agreements commenced on October 2, 2015 and will continue until October 2, 2030; and

(iii) a gas processing contract that commenced on March 1, 2017 and will continue until June 30, 2023.

(5) See "—Transportation Commitments" section below, which excludes the Gathering Agreement, Amended Processing Agreement and specific gas processing contract as discussed above.

(6) Represents firm lease commitments related to our compressors and drilling commitments.

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(7) Represents payments due for an acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas which commenced on March 1, 2014 and will continue until February 28, 2024. The lease agreement includes a contractual requirement for the Company to spend a minimum of $4 million to make permanent improvements over the 10-year life of the lease. The lease agreement does not specify the timing for such improvements to be made within the lease term. The Company has the right to terminate the lease obligation without penalty at any time with six months advance written notice and payment of any accrued leasehold expenses.

Transportation Commitments

As of December 31, 2018, in our Catarina area, we have two additional contracts that require us to deliver portions of our natural gas, with delivery requirements through 2021 and 2022, respectively. Under our contract expiring in 2021, we are required to deliver approximately 47.5 Bcf of natural gas. Under our contract expiring in 2022, we are required to deliver approximately 158.3 Bcf of natural gas.

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.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that require us to deliver portions of our NGLs. This contract expires in 2023 and requires us to deliver approximately 12.5 MMBbls of NGLs.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that require us to deliver portions of our oil. This contract expires in 2020 and requires us to deliver approximately 3.0 MMBbls of oil.

In addition, as is common in our industry, we are party to certain gathering agreements that obligate us to deliver a specified volume of production over a defined time horizon. We, as the operator, on behalf of ourselves and the other working interest partners, are party to two gathering agreements that require us to deliver variable monthly quantities 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.

Development Commitments

On June 30, 2014, the Company completed the acquisition of 106,000 net contiguous acres in Dimmit, La Salle and Webb counties, Texas in the Eagle Ford Shale from SWEPI LP and Shell Gulf of Mexico Inc. (the "Catarina Acquisition"). In connection with the Catarina Acquisition, the undeveloped acreage we acquired is subject to a continuous drilling commitment. Such drilling commitments require 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. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

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

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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.

Off Balance Sheet Arrangements

As of December 31, 2018, we did not have any off balance sheet arrangements.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements that have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in “Item 8. Financial Statements and Supplementary Data — Note 2, Basis of Presentation and Summary of Significant Accounting Policies.” When we prepare our financial statements, we review our estimates, including those related to revenue from the sale of oil, natural gas and NGLs, reserves of oil, natural gas and NGLs, fair value of derivative instruments, abandonment liabilities, income taxes, commitments and contingencies, depreciation, and depletion and amortization. Our estimates are based on historical experience and various assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties

The Company’s oil and natural gas properties are accounted for using the successful efforts method of accounting. All direct and certain indirect costs associated with the acquisition, successful exploration and development of oil and natural gas properties are capitalized. Once evaluated, these costs, as well as the estimated costs to retire the assets, are included in the amortization base and amortized to depletion expense using the units of production method. Depletion is calculated based on estimated proved oil and natural gas reserves. The sale or disposition of oil and natural gas properties results in a gain or loss unless the sale or disposition does not cause a significant change in the relationship between costs and the estimated quantities of proved reserves, in which case the proceeds are applied to reduce net capitalized costs.

Depreciation, depletion and amortization—DD&A is calculated using the units of production method based upon estimates of proved reserves of oil, natural gas and NGLs and conversion of production of the same to a common unit of measure based upon the relative energy content of each hydrocarbon. All capitalized costs of oil and natural gas properties are amortized using the units of production method based on proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from the amortization base are transferred to proved oil and natural gas properties and amortization begins. All other non-oil and natural gas assets are stated at historical cost, net of impairments and depreciation, which is calculated using the straight-line method over their respective useful lives.

In arriving at depletion rates under the units of production method, the quantities of recoverable oil and natural gas reserves are established based on estimates made by internal and third-party engineers and geologists, which require significant judgment, as does the projection of future production volumes and levels of future costs. These judgments may have a significant impact on the calculation of depletion expense. At December 31, 2018, a 10% positive revision to

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proved reserves would decrease the depletion rate by approximately $0.67 per Boe and a 10% negative revision to proved reserves would increase the depletion rate by approximately $0.98 per Boe. All of these judgments, including the determination of the existence of proved reserves once a well has been drilled, may have significant impact on the calculation of depletion expense.

Impairment of Oil and Natural Gas Properties —Capitalized costs (net of accumulated depreciation, depletion and amortization and impairment) of proved oil and natural gas properties are subjected to an impairment test when facts and circumstances indicate that their carrying value may not be recoverable. Net capitalized costs of proved oil and natural gas properties are compared to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. The underlying commodity prices embedded in the estimated cash flows are the product of a process based on NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that are expected to impact the realizable price. During the years ended December 31, 2018 and 2016, we recorded proved property impairment of $6.6 million and $3.7 million, respectively, due to the decline of oil and natural gas prices during the periods. We did not record a proved property impairment for the year ended December 31, 2017. Changes in production rates, levels of reserves, future development costs, and other factors will determine our actual impairment analyses in future periods.

Unproved Properties—Costs associated with unproved properties and properties under development are excluded from the amortization base until the properties have been evaluated. Additionally, the costs associated with leasehold acreage, and wells currently being drilled are also initially excluded from the amortization base. Unproved properties are identified on a project basis, with a project being an area in which significant leasehold interests are acquired within a contiguous area. Unproved properties are reviewed periodically by management and transferred into the amortization base when management determines that a core area has been evaluated through drilling operations or thorough geologic evaluation. Considerable judgment is necessary in determining when unproved properties become impaired. We recorded impairment of $7.8 million to our unproved oil and natural gas properties for the year ended December 31, 2018 due to acreage expiration from changes in our development plan. We recorded an impairment of $39.6 million to our unproved oil and natural gas properties for the year ended December 31, 2017 due to a write-down of our TMS acreage to fair value due to the SR Acquisition. We recorded impairment of $43.7 million to our unproved oil and natural gas properties due to acreage abandonment from changes in development plan for the year ended December 31, 2016.

Oil and Natural Gas Reserves

The Company's most significant estimates relate to its proved reserves of oil, natural gas and NGLs. The estimates of reserves of oil, natural gas and NGLs as of December 31, 2018, 2017 and 2016 are based on reports prepared by Ryder Scott, a third-party engineering firm.

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

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

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

Reserves and their relation to estimated future net cash flows impact the depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The reserve estimates and the projected cash flows derived from these reserve estimates are prepared in accordance with SEC

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guidelines. The independent engineering firm noted above adheres to these guidelines when preparing their reserve reports. The accuracy of the reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered. Additionally, with other factors held constant, if the commodity prices used in our reserve report as of December 31, 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.

Asset Retirement Obligations

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

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount more likely than not (a likelihood of more than 50%) to be recovered.

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

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is estimated. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact the Company's financial position, results of operations and cash flows. The Company did not have any material uncertain tax positions during the years ended December 31, 2018, 2017 or 2016.

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

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

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

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Commodity Price Risk

Our primary market risk exposure relates to the prices we receive for our oil, natural gas and NGL production. The prices we ultimately realize for our oil, natural gas and NGLs are based on a number of variables, including prevailing index prices attributable to our production and certain differentials to those index prices. Pricing for oil, natural gas and NGLs is volatile and unpredictable, and this volatility is expected to continue in the future. In addition, the prices we receive for our oil, natural gas and NGLs depend on many factors outside of our control, such as the supply and demand for oil, natural gas and NGLs, the relative strength of the global economy, the actions of OPEC and international sanctions against countries such as Iran and Venezuela.

To reduce the impact on the Company's business and results of operations from fluctuations in the prices we receive for oil, natural gas and NGLs, and to protect the economics of property acquisitions at the time of execution, the Company periodically enters into derivative contracts with respect to a portion of its projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions may include fixed price swaps (whereby, on the settlement date, the Company will receive or pay an amount based on the difference between a pre-determined fixed price and a variable market price for a notional quantity of production), put options (whereby the Company pays a cash premium in order to establish a fixed floor price for a notional quantity of production and, on the settlement date, receives the excess, if any, of the fixed price floor over a variable market price), and costless collars (whereby, on the settlement date, the Company receives the excess, if any, of a variable market price over a fixed floor price, up to a fixed ceiling price for a notional quantity of production). In addition, the Company periodically enters into call swaptions as a way to achieve greater downside price protection than offered under prevailing fixed price swaps by agreeing to increase the notional quantity hedged or extend the notional quantity settlement period under a fixed price swap at the counterparty's election on a designated date. The market for NGL hedging has historically been constrained in terms of price, tenor, liquidity and availability of counterparties. The Company does not currently have any NGL hedges in place. We continue to assess our exposure to NGL price volatility and the NGL hedging market in general and may seek to enter into derivatives in the future on a portion of our projected NGL production. In addition, from time to time, the Company may evaluate strategies to unwind, terminate, cancel, restructure or otherwise modify its existing commodity derivatives in connection with the ongoing assessment of its general risk profile, including projected future production levels, covenant and other compliance requirements, its overall financial position and other considerations.

These hedging activities, which are regulated by the terms of the Credit Agreement, the SN UnSub Credit Agreement and SN UnSub's organizational documents, are intended to support oil and natural gas prices at targeted levels and manage exposure to oil and natural gas price fluctuations. It is our policy to enter into derivative contracts only with counterparties that are creditworthy and competitive market participants. Any derivatives that are with (x) lenders to the SN UnSub Credit Agreement, or (y) counterparties designated as secured under the Credit Agreement are, in each case, collateralized by the assets securing the applicable facility, and, therefore, do not currently require the posting of cash collateral. Any derivatives that are with (x) non-lender counterparties, as designated under the SN UnSub Credit Agreement, or (y) counterparties that are not designated as secured under the Credit Agreement are, in each case, unsecured and do not require the posting of cash or other collateral. It is never the Company's intention to enter into derivative contracts for speculative trading purposes. Please refer to "Item 8. Financial Statements and Supplementary Data — Note 11, Derivative Instruments" for a description of all of our derivatives covering anticipated future production as of December 31, 2018.

The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon conditions in the commodity and financial markets at the time we enter into these transactions, which may result in higher or lower hedge prices for oil, natural gas and NGLs under these contracts, if any, as compared to the hedge prices under our current contracts. Accordingly, our hedging strategy may not protect us from significant or sustained declines in the prices of oil, natural gas and NGLs for future production. Conversely, our hedging strategy may limit our ability to realize incremental cash flows from commodity price increases during periods for which we have hedged our production. As such, our hedging strategy may not prove effective in adequately protecting us from changes in the prices of oil, natural gas and NGLs that could have a significant adverse effect on our liquidity, business, financial condition and results of operations.

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At December 31, 2018, the fair value of our commodity derivative contracts was a net asset of approximately $21.2 million. A 10% increase or decrease in the oil and natural gas index prices above the December 31, 2018 prices would result in a decrease or increase, respectively, in the fair value of our commodity derivative contracts of $25.9 million. On a consolidated basis, the Company has hedged approximately 3,149,000 Bbls of its 2019 oil production and 17,644,000 MMBtu of its 2019 natural gas production. SN UnSub's production represents approximately 54% of the hedged oil volumes and approximately 59% of the hedged gas volumes.

Credit Risk

Our credit risk relates primarily to trade receivables and financial derivative instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For derivatives entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We may also be exposed to credit risk due to the concentration of our customers in the energy industry, as our customers may be similarly affected by prolonged changes in economic and industry conditions, or by the sale of our oil and natural gas production to a limited number of purchasers.

We actively manage this credit risk by selecting counterparties that we believe to be highly creditworthy and continuing to monitor their financial position. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

As of December 31, 2018, the substantial majority of our credit exposure was with investment grade counterparties. We believe exposure to losses related to credit risk at December 31, 2018 was not material, which is consistent with all years presented.

Interest Rate Risk

As of December 31, 2018, we had no borrowings outstanding under the Credit Agreement, $167.5 million outstanding under the UnSub Credit Agreement and $23.5 million outstanding under the SR Credit Agreement, all of which carry variable interest rates. Our Senior Notes bear interest at fixed interest rates. A one percent change in the interest rates on the outstanding borrowings under the SN UnSub Credit Agreement and the SR Credit Agreement would result in an approximately $1.7 million change in annual interest expense. We believe our exposure to interest-related losses at December 31, 2018 was not material.

We currently do not have any interest rate derivative contracts in place. We continue to assess our exposure to fluctuating interest rates and may seek to enter into interest rate derivatives in the future on a portion of our variable rate indebtedness.

Item 8. Financial Statements and Supplementary Data

The information required by this Item is included in this report as set forth in the "Index to Consolidated Financial Statements" beginning on page F 1 of this Annual Report on Form 10-K and is incorporated by reference herein.

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

None.

## Item 9A. Controls and Procedures

### Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the

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effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2018 at the reasonable assurance level.

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

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on this assessment and such criteria, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

KPMG, an independent registered public accounting firm, has issued its report on the effectiveness of the Company's internal control over financial reporting at December 31, 2018. The report from KPMG is included in this Item 8 under the heading "Report of Independent Registered Public Accounting Firm."

Report of Independent Registered Public Accounting Firm

Please see Report of Independent Public Accounting Firm under "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ending December 31, 2018 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our directors, executive officers and certain corporate governance items will be included in an amendment to this Form 10 K or in the proxy statement for the 2019 Annual Meeting of Stockholders, in either case, to be filed within 120 days after December 31, 2018, and is incorporated by reference to this report.

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## Item 11. Executive Compensation

Information regarding executive compensation will be included in an amendment to this Form 10 K or in the proxy statement for the 2019 Annual Meeting of Stockholders and is incorporated by reference to this report.

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

Information regarding beneficial ownership and management and related stockholder matters will be included in an amendment to this Form 10 K or in the proxy statement for the 2019 Annual Meeting of Stockholders and is incorporated by reference to this report.

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

Information regarding certain relationships and related transactions and director independence will be included in an amendment to this Form 10 K or in the proxy statement for the 2019 Annual Meeting of Stockholders and is incorporated by reference to this report.

## Item 14. Principal Accountant Fees and Services

Information regarding principal accounting fees and services will be included in an amendment to this Form 10 K or in the proxy statement for the 2019 Annual Meeting of Stockholders and is incorporated by reference to this report.

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GLOSSARY OF SELECTED OIL AND NATURAL GAS TERMS

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

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

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

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

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

Bcf:  One billion cubic feet of natural gas.

black oil:  A quality of oil with an API gravity of 15-45° with a gas to oil ratio of 200-900 cubic feet per barrel or less.

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

Boe/d:  One Boe per day.

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

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

condensate: A liquid hydrocarbon with an API gravity of 50-100°.

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

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

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storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

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

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

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

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

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

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

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

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

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

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

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

MBbls: One thousand Bbls.

MBoe: One thousand Boe.

Mcf: One thousand cubic feet of natural gas.

MMBbls: One million Bbls.

MMBoe: One million Boe.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

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

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

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

NGLs:  The combination of ethane, propane, butane, natural gasolines and other components that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX:  New York Mercantile Exchange.

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

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

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

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

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

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

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

proved developed non-producing reserves:  Reserves that are expected to be recovered from completion intervals which are open at the time of the estimate but which have not yet started producing, wells which were shut-in for market conditions or pipeline connections, or wells not capable of production for mechanical reasons; reserves that are expected to be recovered from zones in existing well which will require additional completion work or future re-completion prior to start production.

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

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

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

recompletion:  The action of reentering an existing wellbore to redo or repair the original completion in order to increase the well’s productivity.

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

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

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

spacing:  The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 600 foot well-spacing) and is often established by regulatory agencies.

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

trend:  A geographic area with hydrocarbon potential.

undeveloped acreage:  Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

unproved properties:  Properties with no proved reserves.

volatile oil:  A quality of oil with an API gravity of 42-55° with a gas  to  oil ratio of 900-3,500 cubic feet per barrel.

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

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

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

WTI: West Texas Intermediate oil.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(1)Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2)Financial Statement Schedules:

None.

(3)Exhibits:

The exhibits required by Item 601 of Regulation S-K are listed in subparagraph (b) below.

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

| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 2.1 | ** | Purchase and Sale Agreement, dated as of July 5, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on July 6, 2016, and incorporated herein by reference). |
| 2.2 | ** | Purchase and Sale Agreement, dated as of October 6, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company's Current |

Report on Form 8-K on October 7, 2016, and incorporated herein by reference).

| | | |
|---|---|---|
| 2.3 | ** | Purchase and Sale Agreement, dated as of October 6, 2016, by and among SN Cotulla Assets, LLC, SN Palmetto, LLC, SEP Holdings IV, LLC and Sanchez Production Partners LP (filed as Exhibit 2.2 to the Company's Current Report on Form 8-K on October 7, 2016, and incorporated herein by reference). |
| 2.4 | ** | Purchase and Sale Agreement, dated as of October 6, 2016, by and among Sanchez Energy Corporation, SN Terminal, LLC and Sanchez Production Partners LP (filed as Exhibit 2.3 to the Company's Current Report on Form 8-K on October 7, 2016, and incorporated herein by reference). |
| 2.5 | ** | Purchase and Sale Agreement, dated as of October 24, 2016, by and among SN Cotulla Assets, LLC, Carrizo (Eagle Ford) LLC, Carrizo Oil & Gas, Inc., and for the limited purposes set forth therein, Sanchez Energy Corporation (filed as Exhibit 2.1 on the Company's Current Report on Form 8-K on January 13, 2017, and incorporated herein by reference). |
| 2.6 | ** | Purchase and Sale Agreement, dated as of January 12, 2017, by and among Anadarko E&P Onshore LLC, Kerr-McGee Oil & Gas Onshore LP, SN EF Maverick, LLC, SN EF UnSub, LP, Aguila Production, LLC, and solely for the purposes of Section 15.22 and Schedule 13.4(a), Sanchez Energy Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on January 17, 2017, and incorporated herein by reference). |
| 2.7 | ** | Purchase and Sale Agreement, dated as of August 17, 2017, by and between SN Cotulla Assets, LLC and Vitruvian Exploration IV, LLC. (filed as Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q on November 6, 2017, and incorporated herein by reference). |

| Exhibit No. | Description of Exhibit |
|---|---|
| 3.1 | Restated Certificate of Incorporation of Sanchez Energy Corporation, effective as of May 28, 2013 (filed as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q on November 8, 2013, and incorporated herein by reference). |
| 3.2 | Certificate of Designations of Series C Junior Participating Preferred Stock of Sanchez Energy Corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on July 29, 2015, and incorporated herein by reference). |
| 3.3 | Amended and Restated Bylaws dated as of December 13, 2011 (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K on December 19, 2011, and incorporated herein by reference). |
| 3.4 | Certificate of Amendment to Restated Certificate of Incorporation of Sanchez Energy Corporation, dated May 24, 2018 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on May 24, 2018 (File No. 001-35372) and incorporated herein by reference). |
| 4.1 | Form of Common Stock Certificate (filed as Exhibit 4.1 to Amendment No. 3 to the Company's Registration Statement on Form S-1 (File. No. 333-176613) on November 25, 2011, and incorporated herein by reference). |
| 4.2 | Indenture, dated as of June 13, 2013, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and U.S. Bank National Association as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8- K on June 14, 2013 and incorporated herein by reference). |
| 4.3 | First Supplemental Indenture, dated as of September 11, 2013, by and among Sanchez Energy Corporation, SN TMS, LLC, the existing guarantors and U.S. Bank National Association as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 19, 2013 and incorporated herein by reference). |
| 4.6 | Registration Rights Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Sanchez Energy Partners I, LP (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 4.7 | Second Supplemental Indenture, dated as of June 2, 2014, by and among Sanchez Energy Corporation, SN Catarina, LLC, the existing guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.6 to the Company's Registration Statement on Form S-4 (File No. 333-196660)on June 11, 2014, and incorporated herein by reference). |
| 4.8 | Indenture, dated as of June 27, 2014, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference). |
| 4.11 | Rights Plan dated as of July 28, 2015, by and between Sanchez Energy Corporation and Continental Stock Transfer & Trust Company, as Rights Agent (including the form of Certificate of Designations of Series C Junior Participating Preferred Stock attached thereto as Exhibit A, the form of Right Certificate attached thereto as Exhibit B and the Summary of Rights attached thereto as Exhibit C) (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 29, 2015, and incorporated herein by reference). |

| | |
|---|---|
| 4.12 | Instrument of Resignation, Appointment and Acceptance (7.75% Senior Notes), dated as of May 20, 2016, by and among Sanchez Energy Corporation, Delaware Trust Company and U.S. Bank National Association (filed as Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q on August 8, 2016, and incorporated herein by reference). |

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| Exhibit No. | Description of Exhibit |
| --- | --- |
| 4.13 | Instrument of Resignation, Appointment and Acceptance (6.125% Senior Notes), dated as of May 20, 2016, by and among Sanchez Energy Corporation, Delaware Trust Company and U.S. Bank National Association (filed as Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q on August 8, 2016, and incorporated herein by reference). |
| 4.14 | Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Gavilan Resources Holdings—A, LLC (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference). |
| 4.15 | Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Gavilan Resources Holdings—B, LLC (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference). |
| 4.16 | Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Gavilan Resources Holdings—C, LLC (filed as Exhibit 4.3 to the Company's Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference). |
| 4.17 | Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and GSO Capital Opportunities Fund III LP, GSO Energy Select Opportunities Fund LP, GSO Energy Partners—A LP, GSO Energy Partners—B LP, GSO Energy Partners—C LP, GSO Energy Partners—C II LP, GSO Energy Partners—D LP, GSO Credit Alpha Fund LP, GSO Harrington Credit Alpha Fund (Cayman) L.P., and GSO Capital Solutions Funds II LP (filed as Exhibit 4.4 to the Company's Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference). |
| 4.18 | Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Intrepid Private Equity V-A, LLC ("Intrepid") (filed as Exhibit 4.5 to the Company's Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference). |
| 4.19 | Amendment No. 1, dated as of March 1, 2017, to Rights Agreement, dated as of July 28, 2015, by and between Sanchez Energy Corporation and Continental Stock Transfer & Trust Company, as rights agent (incorporated by reference from Exhibit 4.2 to the Company's Form 8-A/A filed with the SEC on March 3, 2017) |
| 4.20 | Registration Rights Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation and the GSO Funds, as defined therein (incorporated by reference from Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 4.21 | Registration Rights Agreement, dated March 1, 2017, by and between Sanchez Energy Corporation and Intrepid Private Equity V-A, LLC (incorporated by reference from Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 4.22 | Registration Rights Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation, Gavilan Resources Holdings – A, LLC, Gavilan Resources Holdings – B, LLC and Gavilan Resources Holdings – C, LLC (incorporated by reference from Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 4.23 | |

Standstill and Voting Agreement, dated February 6, 2017, by and among Sanchez Energy Corporation and the GSO Funds, as defined therein (incorporated by reference from Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).

4.24 Amendment No. 1 to Standstill and Voting Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation and the GSO Funds, as defined therein (incorporated by reference from Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).

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| Exhibit No. | Description of Exhibit |
|---|---|
| 4.25 | Standstill and Voting Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation, Blackstone Capital Partners VII L.P. and Blackstone Energy Partners II L.P. (incorporated by reference from Exhibit 4.6 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 4.26 | First Supplemental Indenture (6.125% Senior Notes due 2023), dated March 7, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company as trustee (incorporated by reference from Exhibit 4.13 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 4.27 | Third Supplemental Indenture (7.75% Senior Notes due 2021), dated March 7, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company, as trustee (incorporated by reference from Exhibit 4.14 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 4.28 | Indenture (7.25% Senior Secured First Lien Notes due 2023), dated February 14, 2018, by and among Sanchez Energy Corporation, the guarantors party thereto, Delaware Trust Company, as trustee, and Royal Bank of Canada, as collateral trustee (incorporated by reference from Exhibit 4.1 to the Company’s Current Report on Form 8-K on February 20, 2018, and incorporated herein by reference). |
| 4.29 | Fourth Supplemental Indenture (7.75% Senior Notes due 2021), dated as of April 3, 2018, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company, as trustee (incorporated by reference from Exhibit 4.1 to the Company’s Quarterly Report on Form 10-Q on August 7, 2018, and incorporated herein by reference). |
| 4.30 | Second Supplemental Indenture (6.125% Senior Notes due 2023), dated as of April 3, 2018, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company, as trustee (incorporated by reference from Exhibit 4.2 to the Company’s Quarterly Report on Form 10-Q on August 7, 2018, and incorporated herein by reference). |
| 4.31 | First Supplemental Indenture (7.25% Senior Secured First Lien Notes due 2023), dated as of April 3, 2018 among Sanchez Energy Corporation, the guarantors party thereto, Delaware Trust Company, as trustee and Royal Bank of Canada, as collateral trustee (incorporated by reference from Exhibit 4.3 to the Company’s Quarterly Report on Form 10-Q on August 7, 2018, and incorporated herein by reference). |
| 4.32 | Amendment No. 2 to Rights Agreement, dated as of July 27, 2018, by and between Sanchez Energy Corporation and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.3 to the Company’s Amendment No. 2 to Registration Statement on Form 8-A/A filed with the SEC on August 1, 2018 (File No. 001-35372) and incorporated herein by reference). |
| 10.1 | Services Agreement, dated as of December 19, 2011, by and between Sanchez Oil & Gas Corporation and Sanchez Energy Corporation (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |

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| 10.2 | | Geophysical Seismic Data Use License Agreement, dated as of December 19, 2011, by and among Sanchez Oil & Gas Corporation, Sanchez Energy Corporation, SEP Holdings III, LLC and SN Marquis LLC (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.3 | * | Indemnification Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Antonio R. Sanchez, III (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |

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| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 10.4 | * | Indemnification Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Gilbert A. Garcia (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.5 | * | Form of Restricted Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference). |
| 10.6 | * | Form of Restricted Stock Agreement for Non-employee Directors (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference). |
| 10.7 | * | Form of Restricted Stock Agreement for Antonio R. Sanchez, III (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference). |
| 10.8 | * | Indemnification Agreement, dated as of March 9, 2012, by and between Sanchez Energy Corporation and Greg Colvin (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 14, 2012, and incorporated herein by reference). |
| 10.9 | * | Indemnification Agreement, dated as of March 9, 2012, by and between Sanchez Energy Corporation and Kirsten A. Hink (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 14, 2012, and incorporated herein by reference). |
| 10.10 | * | Indemnification Agreement, dated as of November 27, 2012, by and between Sanchez Energy Corporation and A.R. Sanchez, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference). |
| 10.11 | * | Indemnification Agreement, dated as of November 27, 2012, by and between Sanchez Energy Corporation and Alan G. Jackson (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference). |
| 10.12 | | Second Amended and Restated Credit Agreement, dated as of June 30, 2014, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC, as loan parties, Royal Bank of Canada, as administrative agent, Capital One, National Association, as syndication agent, Compass Bank, SunTrust Bank as co-documentation agents, RBC Capital Markets, LLC as sole lead arranger and sole book runner, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference). |
| 10.13 | | First Amendment to Second Amended and Restated Credit Agreement, dated as of September 9, 2014, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC, as loan parties, Royal Bank of Canada, as administrative agent, Capital One, National Association, as syndication agent, Compass Bank, SunTrust Bank as co-documentation agents, RBC Capital Markets, LLC as sole lead |

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| | | arranger and sole book runner, and the lenders party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on September 15, 2014, and incorporated herein by reference). |
| 10.14 | * | Indemnification Agreement, dated as of November 4, 2014, by and between Sanchez Energy Corporation and Sean Maher (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 6, 2014, and incorporated herein by reference). |

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| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 10.15 | | Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 31, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 1, 2015, and incorporated herein by reference). |
| 10.16 | * | Indemnification Agreement, dated as of May 5, 2015, by and between Sanchez Energy Corporation and Thomas Brian Carney (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 8, 2015, and incorporated herein by reference). |
| 10.17 | * | Sanchez Energy Corporation Third Amended and Restated 2011 Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K on May 26, 2016, and incorporated herein by reference). |
| 10.18 | * | Indemnification Agreement, dated as of October 1, 2015, by and between Sanchez Energy Corporation and Eduardo Sanchez (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on October 6, 2015, and incorporated herein by reference). |
| 10.19 | | Third Amendment to Second Amended and Restated Credit Agreement, dated as of July 20, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on November 8, 2013, and incorporated herein by reference). |
| 10.20 | | Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of September 29, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on November 8, 2013, and incorporated herein by reference). |
| 10.21 | | Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 30, 2015, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, and SN Catarina, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 4, 2015, and incorporated herein by reference). |
| 10.22 | | Sixth Amendment to Second Amended and Restated Credit Agreement, dated as of January 22, 2016, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, and SN Catarina, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on January 25, 2016, and incorporated herein by reference). |
| 10.23 | | Seventh Amendment to Second Amended and Restated Credit Agreement, dated as of March 18, 2016, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, and SN Catarina, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on March 21, 2016, and incorporated herein by reference). |

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| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 10.24 | | Eighth Amendment to Second Amended and Restated Credit Agreement, dated as of April 18, 2017, by and among Sanchez Energy Corporation, as borrower, SN Palmetto, LLC (f/k/a SEP Holdings III, LLC), SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, SN EF Maverick, LLC, and Rockin L Ranch Company, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as exhibit 10.1 to the Company's Current Report on Form 8-K on April 24, 2017, and incorporated herein by reference). |
| 10.25 | | Ninth Amendment to Second Amended and Restated Credit Agreement, dated as of July 1, 2017, by and among Sanchez Energy Corporation, as borrower, SN Palmetto, LLC (f/k/a SEP Holdings III, LLC), SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, SN EF Maverick, LLC, and Rockin L Ranch Company, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto. (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on November 6, 2017, and incorporated herein by reference). |
| 10.26 | | Letter Agreement, dated as of December 9, 2016, by and among Royal Bank of Canada, as administrative agent under the Second Amended and Restated Credit Agreement, as amended, Sanchez Energy Corporation, as borrower and the other parties thereto (filed as Exhibit 10.29 to the Company's Annual Report on Form 10-K on February 27, 2017, and incorporated herein by reference). |
| 10.27 | * | Indemnification Agreement, dated as of December 14, 2015, by and between Sanchez Energy Corporation and Gregory B. Kopel (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 16, 2015, and incorporated herein by reference). |
| 10.28 | * | Indemnification Agreement, dated as of March 8, 2016, by and between Sanchez Energy Corporation and Garrick Hill (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 8, 2016, and incorporated herein by reference). |
| 10.29 | * | Form of Restricted Stock Award Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference). |
| 10.30 | * | Form of Performance Accelerated Restricted Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference). |
| 10.31 | * | Form of Phantom Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference). |
| 10.32 | * | Form of Performance Accelerated Phantom Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference). |
| 10.33 | * | Indemnification Agreement, dated as of August 2, 2016, by and between Sanchez Energy Corporation and Robert Nelson (filed as Exhibit 10.1 on the Company's Current Report on Form 8-K on August 3, 2016, and incorporated herein by reference). |
| 10.34 | * | Indemnification Agreement, dated as of November 3, 2016, by and between Sanchez Energy Corporation and Patricio D. Sanchez (filed as Exhibit 10.1 on the Company's Current Report on Form 8-K on November 9, 2016, and incorporated herein by reference). |

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| 10.35 | ** | Securities Purchase Agreement, dated as of January 12, 2017, by and among Sanchez Energy Corporation, SN UR Holdings, LLC, SN EF UnSub Holdings, LLC, SN EF UnSub, LP, SN EF UnSub GP, LLC, GSO ST Holdings Associates LLC, and GSO ST Holdings LP (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 17, 2017, and incorporated herein by reference). |

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| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 10.36 | ** | Interim Investors Agreement, dated as of January 12, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, SN EF UnSub, LP, Aguila Production, LLC, Aguila Production HoldCo, LLC, Blackstone Capital Partners VII L.P., and Blackstone Energy Partners II L.P. (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 12, 2017, and incorporated herein by reference). |
| 10.37 | | Underwriting Agreement, dated January 31, 2017, by and between Sanchez Energy Corporation and J.P. Morgan Securities LLC, as representative of the several underwriters named therein (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on February 2, 2017, and incorporated herein by reference). |
| 10.38 | | Amended and Restated Agreement of Limited Partnership of SN EF UnSub, LP, dated March 1, 2017 (incorporated by reference from Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.39 | | Amended and Restated Limited Liability Company Agreement of SN EF UnSub GP, LLC, dated March 1, 2017 (incorporated by reference from Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.40 | | Amended and Restated Limited Liability Company Agreement of Gavilan Resources HoldCo, LLC, dated March 1, 2017 (incorporated by reference from Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.41 | | First Lien Credit Agreement, dated March 1, 2017, by and among SN EF UnSub, LP, JPMorgan Chase Bank, N.A., Citigroup Global Markets Inc., Capital One, National Association, RBC Capital Markets LLC, BMO Harris Bank, NA, ING Capital LLC and SunTrust Robinson Humphrey, Inc. (incorporated by reference from Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.42 | | Shareholders Agreement, dated March 1, 2017, by and between Gavilan Resources HoldCo, LLC and Sanchez Energy Corporation (incorporated by reference from Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.43 | | Amended and Restated Securities Purchase Agreement, dated February 28, 2017, by and among Sanchez Energy Corporation, SN UR Holdings, LLC, SN EF UnSub Holdings, LLC, SN EF UnSub, LP, SN EF UnSub GP, LLC, Intrepid Private Equity V-A, LLC, GSO ST Holdings Associates LLC and GSO ST Holdings LP. (incorporated by reference from Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.44 | | Interim Investors Agreement, dated January 12, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, SN EF UnSub, LP, Aguila Production, LLC, Aguila Production HoldCo, LLC, Blackstone Capital Partners VII L.P. and Blackstone Energy Partners II L.P. (incorporated by reference from Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.45 | | Joint Development Agreement, dated March 1, 2017, by and among Gavilan Resources, LLC, SN EF Maverick, LLC, SN EF UnSub, LP and, solely for the purposes stated therein, Sanchez Energy Corporation (incorporated by reference from Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |

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| 10.46 | Management Services Agreement, dated March 1, 2017, by and between Sanchez Oil & Gas Corporation and SN EF UnSub, LP. (incorporated by reference from Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |

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| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 10.47 | | Management Services Agreement, dated March 1, 2017, by and among Gavilan Resources HoldCo, LLC, SN Comanche Manager, LLC and, solely for the limited purposes stated therein, SN EF Maverick, LLC (incorporated by reference from Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.48 | | Letter Agreement, dated as of March 1, 2017, between SN Comanche Manager, LLC and Sanchez Oil & Gas Corporation (incorporated by reference from Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.49* | | Form of Performance Stock Award Agreement (incorporated by reference from Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference). |
| 10.50 | | Equity Distribution Agreement, dated as of May 25, 2017, among Sanchez Energy Corporation, Citigroup Global Markets Inc., BMO Capital Markets Corp., Capital One Securities, Inc., RBC Capital Markets, LLC and SunTrust Robinson Humphrey, Inc. (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on May 25, 2017, and incorporated herein by reference). |
| 10.51 | | Mutual Written Consent to Terminate Purchase and Sale Agreement, dated September 11, 2017, by and among Sanchez Energy Corporation, SN Terminal, LLC and Sanchez Midstream Partners LP. (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on November 6, 2017, and incorporated herein by reference). |
| 10.52 | | Purchase Agreement, dated February 7, 2018, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc., as representative of the several initial purchasers named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on February 12, 2018, and incorporated herein by reference). |
| 10.53 | | Third Amended and Restated Credit Agreement dated as of February 14, 2018 among Sanchez Energy Corporation, as borrower, Royal Bank of Canada, as administrative agent and collateral agent, RBC Capital Markets, as Arranger, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on February 20, 2018, and incorporated herein by reference). |
| 10.54 | | K on February 12, 2018, and incorporated herein by reference). |
| 10.55 | * | Form of Performance Cash-Settled Phantom Stock Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference). |
| 10.56 | * | Form of Performance Share-Settled Phantom Stock Agreement (filed as Exhibit 10.2 to the Company's Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference). |
| 10.57 | * | Form of Restricted Stock Agreement (filed as Exhibit 10.3 to the Company's Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference). |
| 10.58 | * | Form of Phantom Stock Agreement (filed as Exhibit 10.4 to the Company's Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference). |

10.59 K on May 15, 2018, and incorporated herein by reference)

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| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 10.60 | * | Professional Services Agreement, effective August 22, 2018 by and between Sanchez Oil & Gas Corporation and Christopher D. Heinson (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on November 1, 2018, and incorporated herein by reference). |
| 10.61 | * | Indemnification Agreement, dated as of October 26, 2018, between Sanchez Energy Corporation and Eugene I. Davis (filed as Exhibit 10.1 to the Company's Current Report on Form 8 K on November 1, 2018, and incorporated herein by reference). |
| 10.62 | * | Indemnification Agreement, dated as of October 26, 2018, between Sanchez Energy Corporation and Adam C. Zylman (filed as Exhibit 10.2 to the Company's Current Report on Form 8 K on November 1, 2018, and incorporated herein by reference). |
| 10.63 | * | Indemnification Agreement, dated as of October 26, 2018, between Sanchez Energy Corporation and Cameron W. George (filed as Exhibit 10.3 to the Company's Current Report on Form 8 K on November 1, 2018, and incorporated herein by reference). |
| 10.64 | *(a) | Separation Agreement and General Release, dated as of October 26, 2018, between Howard Thill, Sanchez Oil & Gas Corporation and Sanchez Energy Corporation. |
| 21.1 | (a) | List of Subsidiaries of Sanchez Energy Corporation. |
| 23.1 | (a) | Consent of KPMG LLP. |
| 23.2 | (a) | Consent of Ryder Scott Company, L.P. |
| 31.1 | (a) | Sarbanes-Oxley Section 302 certification of Principal Executive Officer. |
| 31.2 | (a) | Sarbanes-Oxley Section 302 certification of Principal Financial Officer. |
| 32.1 | (b) | Sarbanes-Oxley Section 906 certification of Principal Executive Officer. |
| 32.2 | (b) | Sarbanes-Oxley Section 906 certification of Principal Financial Officer. |
| 99.1 | (a) | Ryder Scott Company, L.P. Summary of December 31, 2018 Reserves. |
| 101.INS | (a) | XBRL Instance Document. |
| 101.SCH | (a) | XBRL Taxonomy Extension Schema Document. |
| 101.CAL | (a) | XBRL Taxonomy Extension Calculation Linkbase Document. |
| 101.DEF | (a) | XBRL Taxonomy Extension Definition Linkbase Document. |
| 101.LAB | (a) | XBRL Taxonomy Extension Labels Linkbase Document. |

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| 101.PRE | (a) | XBRL Taxonomy Extension Presentation Linkbase Document. |

(a)Filed herewith.

(b)Furnished herewith.

*Management contract or compensatory plan or arrangement.

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**The exhibits and schedules to this agreement have been omitted form this filing pursuant to Item 601(b)(2) of Regulation S K. The Company will furnish copies of such omitted exhibits and schedules to the SEC upon request.

The Company has not filed certain instruments with respect to long term debt that did not exceed 10% of the Company's total assets on a consolidated basis. The Company will furnish a copy of such agreements to the SEC upon its request.

Item 16. Form 10-K Summary

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on March 1, 2019.

SANCHEZ ENERGY CORPORATION

By: /s/ Antonio R. Sanchez, III
Antonio R. Sanchez, III
President and Chief Executive Officer

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Antonio R. Sanchez, III and Cameron W. George, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite or necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

| Signature | Title | Date |
|---|---|---|
| /s/ Antonio R. Sanchez, III<br>Antonio R. Sanchez, III | President and Chief Executive Officer<br>(Principal Executive Officer) | March 1, 2019 |
| /s/ Cameron W. George<br>Cameron W. George | Interim Chief Financial Officer<br>(Principal Financial Officer) | March 1, 2019 |
| /s/ Kirsten A. Hink | Senior Vice President and Chief Accounting Officer<br>(Principal Accounting Officer) | March 1, 2019 |

| | | |
|---|---|---|
| Kirsten A. Hink | | |
| /s/ A. R. Sanchez, Jr.<br>A. R. Sanchez, Jr. | Executive Chairman of the Board of Directors | March 1, 2019 |
| /s/ Gilbert A. Garcia<br>Gilbert A. Garcia | Director | March 1, 2019 |
| /s/ Greg Colvin<br>Greg Colvin | Director | March 1, 2019 |
| /s/ Alan G. Jackson<br>Alan G. Jackson | Director | March 1, 2019 |

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|---|---|---|
| /s/ Sean M. Maher<br>Sean M. Maher | Director | March 1, 2019 |
| /s/ Brian Carney<br>Brian Carney | Director | March 1, 2019 |
| /s/ Robert V. Nelson, III<br>Robert V. Nelson, III | Director | March 1, 2019 |
| /s/ Eugene I. Davis<br>Eugene I. Davis | Director | March 1, 2019 |
| /s/ Adam C. Zylman<br>Adam C. Zylman | Director | March 1, 2019 |

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Sanchez Energy Corporation

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Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors

Sanchez Energy Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Sanchez Energy Corporation and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 1, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in note 3 to the consolidated financial statements, the Company has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification Topic 606 Revenue from Contracts with Customers.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the

U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2015.

Houston, Texas
March 1, 2019

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors

Sanchez Energy Corporation:

Opinion on Internal Control over Financial Reporting

We have audited Sanchez Energy Corporation's and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated March 1, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Houston, Texas
March 1, 2019

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Sanchez Energy Corporation

Consolidated Balance Sheets

(in thousands, except share and per share amounts)

| | December 31, 2018 | 2017 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $ 197,613 | $ 184,434 |
| Oil and natural gas receivables | 87,222 | 101,396 |
| Joint interest billings receivables | 33,263 | 22,569 |
| Accounts receivable - related entities | 6,099 | 4,491 |
| Fair value of derivative instruments | 15,714 | 16,430 |
| Other current assets | 33,070 | 21,478 |
| Total current assets | 372,981 | 350,798 |
| Oil and natural gas properties, on the basis of successful efforts accounting: | | |
| Proved oil and natural gas properties | 3,792,431 | 3,130,407 |
| Unproved oil and natural gas properties | 328,643 | 398,605 |
| Total oil and natural gas properties | 4,121,074 | 3,529,012 |
| Less: Accumulated depreciation, depletion, amortization and impairment | (1,761,949) | (1,501,553) |
| Total oil and natural gas properties, net | 2,359,125 | 2,027,459 |
| Other assets: | | |
| Fair value of derivative instruments | 12,102 | 1,428 |
| Investments (Investment in SNMP measured at fair value of $3.9 million and $25.2 million as of December 31, 2018 and 2017, respectively) | 16,664 | 38,462 |
| Other assets | 59,088 | 52,488 |
| Total assets | $ 2,819,960 | $ 2,470,635 |
| LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT) | | |
| Current liabilities: | | |
| Accounts payable | $ 32,382 | $ 14,994 |
| Other payables | 74,628 | 81,970 |
| Accrued liabilities: | | |
| Capital expenditures | 61,970 | 85,340 |
| Other | 102,728 | 84,794 |
| Fair value of derivative instruments | 706 | 56,190 |
| Short term debt | 304 | 23,996 |
| Other current liabilities | 75,581 | 115,244 |
| Total current liabilities | 348,299 | 462,528 |
| Long term debt, net of premium, discount and debt issuance costs | 2,395,408 | 1,930,683 |
| Asset retirement obligations | 46,175 | 36,098 |
| Fair value of derivative instruments | 366 | 17,474 |
| Other liabilities | 21,407 | 65,480 |
| Total liabilities | 2,811,655 | 2,512,263 |
| Commitments and contingencies (Note 15) | | |

| | | |
|---|---|---|
| Mezzanine equity: | | |
| Preferred units ($1,000 liquidation preference, 500,000 units authorized; 500,000 units issued and outstanding as of December 31, 2018 and 2017) | 452,828 | 427,512 |
| Stockholders' equity (deficit): | | |
| Preferred stock ($0.01 par value, 15,000,000 shares authorized; 1,838,985 shares issued and outstanding as of December 31, 2018 and 2017 of 4.875% Convertible Perpetual Preferred Stock, Series A; 3,527,830 shares issued and outstanding as of December 31, 2018 and 2017 of 6.500% Convertible Perpetual Preferred Stock, Series B) | 53 | 53 |
| Common stock ($0.01 par value, 300,000,000 shares authorized; 87,328,424 and 83,984,827 shares issued and outstanding as of December 31, 2018 and 2017, respectively) | 881 | 845 |
| Additional paid-in capital | 1,367,427 | 1,362,118 |
| Accumulated deficit | (1,812,884) | (1,832,156) |
| Total stockholders' equity (deficit) | (444,523) | (469,140) |
| Total liabilities and stockholders' equity (deficit) | $ 2,819,960 | $ 2,470,635 |

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

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Sanchez Energy Corporation

Consolidated Statements of Operations

(in thousands, except per share amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| REVENUES: | | | |
| Oil sales | $ 623,999 | $ 400,045 | $ 241,766 |
| Natural gas liquid sales | 232,085 | 171,139 | 81,744 |
| Natural gas sales | 175,117 | 169,147 | 107,816 |
| Sales and marketing revenues | 25,713 | — | — |
| Total revenues | 1,056,914 | 740,331 | 431,326 |
| OPERATING COSTS AND EXPENSES: | | | |
| Oil and natural gas production expenses | 305,515 | 244,461 | 155,660 |
| Exploration expenses | 3,295 | 5,755 | 403 |
| Sales and marketing expenses | 23,832 | — | — |
| Production and ad valorem taxes | 56,462 | 36,615 | 19,633 |
| Depreciation, depletion, amortization and accretion | 262,481 | 177,078 | 147,485 |
| Impairment of oil and natural gas properties | 14,386 | 39,574 | 47,381 |
| General and administrative expenses | 98,002 | 144,401 | 110,081 |
| Total operating costs and expenses | 763,973 | 647,884 | 480,643 |
| Operating income (loss) | 292,941 | 92,447 | (49,317) |
| Other income (expense): | | | |
| Interest income | 4,351 | 836 | 856 |
| Other income (expense) | (8,001) | 11,102 | 134 |
| Gain on sale of oil and natural gas properties | 1,528 | 81,955 | 85,322 |
| Interest expense | (177,858) | (140,163) | (126,973) |
| Earnings from equity investments | — | 779 | 3,466 |
| Net losses on commodity derivatives | (27,756) | (6,100) | (53,149) |
| Total other income (expense) | (207,736) | (51,591) | (90,344) |
| Income (loss) before income taxes | 85,205 | 40,856 | (139,661) |
| Income tax benefit (expense) | — | 2,336 | (1,825) |
| Net income (loss) | 85,205 | 43,192 | (141,486) |
| Less: | | | |
| Preferred stock dividends | (15,948) | (15,948) | (15,948) |
| Preferred unit dividends and distributions | (47,408) | (44,259) | — |
| Preferred unit amortization | (25,316) | (18,039) | — |
| Net income allocable to participating securities | — | — | — |
| Net loss attributable to common stockholders | $ (3,467) | $ (35,054) | $ (157,434) |
| | | | |
| Net loss per common share - basic and diluted | $ (0.04) | $ (0.46) | $ (2.67) |
| Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted | 81,764 | 75,608 | 58,900 |

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