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

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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					