Sanchez Energy Corp
Form 10-Q
November 06, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10 Q

(Mark One)

ma

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2017

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)

(713) 783 8000

(Registrant's Telephone Number, Including Area Code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non accelerated filer, 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 (Do not check if a smaller reporting company)	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 Exchange Act). Yes No

Number of shares of registrant’s common stock, par value $0.01 per share, outstanding as of November 3, 2017: 84,129,196

Table of Contents

Sanchez Energy Corporation

Form 10 Q

For the Quarterly Period Ended September 30, 2017

Table of Contents

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD LOOKING STATEMENTS

This Quarterly Report on Form 10 Q 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 Quarterly Report on Form 10 Q 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 Quarterly Report on Form 10 Q, words such as “will,” “potential,” “believe,” “estimate,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “plan,” “predict,” “project,” “profile,” “model,” “strateg 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, 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”) (formerly Sanchez Production Partners LP) 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 for, 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 utilize the services, personnel and other assets of Sanchez Oil & Gas Corporation (“SOG”) pursuant to existing services agreements;

- our ability to replace the reserves we produce through drilling and property acquisitions;

- the realized benefits of the acreage acquired in our various acquisitions, including the Comanche Acquisition, and other assets and liabilities assumed in connection therewith;

- our ability to successfully integrate the various assets acquired, including assets acquired in the Comanche Acquisition, into our operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;

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

- the realized benefits of our transactions with SNMP;

- the extent to which our drilling plans are successful in economically developing our acreage in, and to produce reserves and achieve anticipated production levels from, our existing and future projects;

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

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

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

- the credit worthiness and performance of our counterparts, including financial institutions, operating partners and other parties;

- competition in the oil and natural gas exploration and production industry in the marketing of crude oil, natural gas and NGLs and for the acquisition of leases and properties, employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;

- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;

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

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

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

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

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

- unexpected results of litigation filed against us;

- disruptions due to extreme weather conditions, such as extreme rainfall, hurricanes or tornadoes;

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

- the other factors described under "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Part II, Item 1A. Risk Factors" and elsewhere in this Quarterly Report on Form 10 Q and in our other public filings with the Securities and Exchange Commission (the "SEC").

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

Table of Contents

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Sanchez Energy Corporation

Condensed Consolidated Balance Sheets (Unaudited)

(in thousands, except par value and share amounts)

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 174,228	$ 501,917
Oil and natural gas receivables	80,676	41,057
Joint interest billings receivables	17,165	496
Accounts receivable - related entities	7,557	6,401
Fair value of derivative instruments	11,378	—
Other current assets	24,754	12,934
Total current assets	315,758	562,805
Oil and natural gas properties, at cost, using the full cost method:		
Proved oil and natural gas properties	4,266,813	3,164,115
Unproved oil and natural gas properties	446,167	231,424
Total oil and natural gas properties	4,712,980	3,395,539
Less: Accumulated depreciation, depletion, amortization and impairment	(2,869,245)	(2,736,951)
Total oil and natural gas properties, net	1,843,735	658,588
Other assets:		
Fair value of derivative instruments	8,942	—
Investments (Investment in SNMP measured at fair value of $25.6 million and $26.8 million as of September 30, 2017, and December 31, 2016, respectively)	30,833	39,656
Other assets	40,831	25,231
Total assets	$ 2,240,099	$ 1,286,280
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 4,605	$ 1,076

Other payables	69,160	2,251
Accrued liabilities:		
Capital expenditures	114,591	35,154
Other	90,153	82,458
Deferred premium liability	—	2,079
Fair value of derivative instruments	3,685	31,778
Other current liabilities	76,762	22,201
Total current liabilities	358,956	176,997
Long term debt, net of premium, discount and debt issuance costs	1,878,010	1,712,767
Asset retirement obligations	33,578	25,087
Fair value of derivative instruments	7,620	3,236
Other liabilities	52,362	64,333
Total liabilities	2,330,526	1,982,420
Commitments and contingencies (Note 16)		
Mezzanine equity:		
Preferred units ($1,000 liquidation preference, 500,000 units authorized; 500,000 and zero units issued and outstanding as of September 30, 2017 and December 31, 2016, respectively)	414,702	—
Stockholders' equity:		
Preferred stock ($0.01 par value, 15,000,000 shares authorized; 1,838,985 shares issued and outstanding as of September 30, 2017 and December 31, 2016 of 4.875% Convertible Perpetual Preferred Stock, Series A; 3,527,830 shares issued and outstanding as of September 30, 2017 and December 31, 2016 of 6.500% Convertible Perpetual Preferred Stock, Series B)	53	53
Common stock ($0.01 par value, 150,000,000 shares authorized; 83,187,134 and 66,622,624 shares issued and outstanding as of September 30, 2017 and December 31, 2016, respectively)	836	670
Additional paid-in capital	1,352,246	1,112,397
Accumulated deficit	(1,858,264)	(1,809,260)
Total stockholders' deficit	(505,129)	(696,140)
Total liabilities and stockholders' deficit	$ 2,240,099	$ 1,286,280

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

Table of Contents

Sanchez Energy Corporation

Condensed Consolidated Statements of Operations (Unaudited)

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES:				
Oil sales	$ 91,541	$ 64,041	$ 255,913	$ 172,509
Natural gas liquid sales	48,949	19,511	112,922	56,535
Natural gas sales	44,316	31,255	125,518	76,547
Total revenues	184,806	114,807	494,353	305,591
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	72,056	38,997	177,129	128,609
Production and ad valorem taxes	11,346	3,921	26,669	14,052
Depreciation, depletion, amortization and accretion	51,859	37,651	135,916	127,959
Impairment of oil and natural gas properties	—	59,582	—	169,046
General and administrative (1)	14,665	26,936	111,843	70,399
Total operating costs and expenses	149,926	167,087	451,557	510,065
Operating income (loss)	34,880	(52,280)	42,796	(204,474)
Other income (expense):				
Interest income	163	146	670	629
Other income (expense)	(448)	7	3,469	(196)
Gain (loss) on sale of oil and natural gas properties	(2,074)	—	10,202	—
Interest expense	(35,686)	(31,797)	(104,672)	(95,225)
Earnings from equity investments	102	463	779	3,154
Net gains (losses) on commodity derivatives	(41,719)	18,640	56,777	(17,353)
Total other expense	(79,662)	(12,541)	(32,775)	(108,991)
Income (loss) before income taxes	(44,782)	(64,821)	10,021	(313,465)
Income tax benefit (expense)	—	(1,441)	1,208	(1,441)
Net income (loss)	(44,782)	(66,262)	11,229	(314,906)
Less:				
Preferred stock dividends	(3,988)	(3,987)	(11,962)	(11,961)
Preferred unit dividends and distributions	(8,347)	—	(35,762)	—
Preferred unit amortization	(5,517)	—	(12,509)	—
Net income allocable to participating securities	—	—	—	—
Net loss attributable to common stockholders	$ (62,634)	$ (70,249)	$ (49,004)	$ (326,867)
Net loss per common share - basic and diluted	$ (0.81)	$ (1.19)	$ (0.66)	$ (5.56)
	77,453	59,190	74,531	58,782

Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted

(1) Includes non-cash stock-based compensation expense of $911 and $8,310, respectively, for the three months ended September 30, 2017 and 2016, and $17,337 and $17,905, respectively, for the nine months ended September 30, 2017 and 2016.

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

6

Table of Contents

Sanchez Energy Corporation

Condensed Consolidated Statement of Stockholders' Equity for the Nine Months Ended September 30, 2017 (Unaudited)

(in thousands)

	Series A Preferred Stock Shares	Series A Preferred Stock Amount	Series B Preferred Stock Shares	Series B Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Deficit
BALANCE, December 31, 2016	1,839	$ 18	3,528	$ 35	66,987	$ 670	$ 1,112,397	$ (1,809,260)	$ (696,140)
Issuance of warrants	—	—	—	—	—	—	58,958	—	58,958
Issuance of common shares to holders of Preferred Units	—	—	—	—	1,500	15	17,940	—	17,955
Issuance of common stock, net of offering costs of $7.8 million	—	—	—	—	11,500	115	134,896	—	135,011
Dividends on Series A and Series B Preferred stock	—	—	—	—	1,495	15	11,947	(11,962)	—
Dividends on SN UnSub preferred units	—	—	—	—	—	—	—	(29,167)	(29,167)
Distributions - SN UnSub preferred units	—	—	—	—	—	—	—	(6,595)	(6,595)
Accretion of discount on SN UnSub preferred units	—	—	—	—	—	—	—	(12,509)	(12,509)
Restricted stock awards, net of forfeitures	—	—	—	—	2,069	21	(21)	—	—
Stock-based compensation	—	—	—	—	—	—	17,337	—	17,337
Deferred tax benefit - current period	—	—	—	—	—	—	(1,208)	—	(1,208)

etained earnings mpact									
Net income	—	—	—	—	—	—	—	11,229	11,229
BALANCE, September 30, 2017	1,839	$ 18	3,528	$ 35	83,551	$ 836	$ 1,352,246	$ (1,858,264)	$ (505,129)

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

7

Table of Contents

Sanchez Energy Corporation

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Nine Months Ended September 30, 2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 11,229	$ (314,906)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	135,916	127,959
Impairment of oil and natural gas properties	—	169,046
Gain on sale of oil and natural gas properties	(10,202)	—
Stock-based and phantom unit compensation expense	31,093	26,025
Net losses (gains) on commodity derivative contracts	(56,777)	17,353
Net cash settlement received on commodity derivative contracts	17,538	105,111
Gain on embedded derivatives	(2,052)	—
Losses incurred on premiums for derivative contracts	—	18,377
Gain on investments	1,970	—
Amortization of deferred gain on Western Catarina Midstream Divestiture	(11,109)	(11,109)
Amortization of debt issuance costs	9,476	5,865
Accretion of debt discount, net	476	475
Deferred taxes	(1,208)	—
Loss (Gain) on inventory market adjustment	(9)	479
Earnings from equity investments	(779)	(3,154)
Distributions from equity investments	1,191	428
Changes in operating assets and liabilities:		
Accounts receivable	(56,638)	(3,085)
Accounts receivable - related entities	(1,156)	1,462
Other current assets	(16,636)	2,608
Accounts payable	3,529	(2,677)
Other payables	66,909	221
Accrued liabilities	8,030	(2,366)
Other current liabilities	39,943	—
Net cash provided by operating activities	170,734	138,112
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments for oil and natural gas properties	(351,225)	(241,323)
Payments for other property and equipment	(16,255)	(3,962)
Proceeds from sale of oil and natural gas properties	162,801	—
Acquisition of oil and natural gas properties	(1,039,127)	—
Payments for investments	(74)	(28,682)
Sale of investments	12,500	36,977
Net cash used in investing activities	(1,231,380)	(236,990)

CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	323,250	60,000
Repayment of borrowings	(143,500)	(60,000)
Issuance of common stock (net of underwriting discounts of $7.8 million)	135,942	—
Issuance of preferred units	500,000	—
Issuance costs related to preferred units	(20,894)	—
Financing costs	(25,237)	(1,758)
Preferred dividends paid	—	(3,987)
Cash paid to tax authority for employee stock-based compensation awards	(842)	(1,896)
Preferred unit distribution	(35,762)	—
Net cash provided by (used in) financing activities	732,957	(7,641)
Decrease in cash and cash equivalents	(327,689)	(106,519)
Cash and cash equivalents, beginning of period	501,917	435,048
Cash and cash equivalents, end of period	$ 174,228	$ 328,529
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in asset retirement obligations	$ 6,569	$ 1,222
Change in accrued capital expenditures	79,916	(11,322)
SUPPLEMENTAL DISCLOSURE:		
Cash paid for taxes	—	1,996
Cash paid for interest	$ 100,023	$ 94,869

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

Table of Contents

Sanchez Energy Corporation

Notes to the Condensed Consolidated Financial Statements

(Unaudited)

Note 1. Organization

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 U.S. onshore unconventional oil and natural gas resources, with a current focus on the Eagle Ford Shale in South Texas where we have assembled over 286,000 net acres. We also hold an undeveloped acreage position in the Tuscaloosa Marine Shale ("TMS") in Mississippi and Louisiana, which offers future upside opportunity.

Note 2. Basis of Presentation and Summary of Significant Accounting Policies

The accompanying condensed consolidated financial statements are unaudited and were prepared from the Company's records. The condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP" or "U.S. GAAP") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. The Company derived the condensed consolidated balance sheet as of December 31, 2016 from the audited financial statements filed in its Annual Report on Form 10-K for the fiscal year ended December 31, 2016 (the "2016 Annual Report"). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP. These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the 2016 Annual Report, which contains a summary of the Company's significant accounting policies and other disclosures. In the opinion of management, these financial statements include the adjustments and accruals, all of which are of a normal recurring nature, necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results to be expected for the entire year.

As of September 30, 2017, the Company's significant accounting policies are consistent with those discussed in Note 2, "Basis of Presentation and Summary of Significant Accounting Policies," in the notes to the Company's consolidated financial statements contained in the 2016 Annual Report. During the first quarter 2017, as a result of the Comanche Acquisition and related financing, the Company issued preferred equity that is classified as Mezzanine Equity on the Balance Sheet (the "SN UnSub Preferred Units"). Dividends and amortization of the discount on the SN UnSub Preferred Units have an impact on the Earnings per Share calculation as described below.

Earnings per Share

Basic net income (loss) per common share is computed using the two-class method. The two-class method is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines net income (loss) per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. The Company's restricted shares of common stock (see Note 14, "Stock Based Compensation") are participating securities under Accounting Standards Codification ("ASC") 260, "Earnings per Share," because they may participate in undistributed earnings with common stock. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities.

To determine net income (loss) allocated to each class of ownership (common equity and SN UnSub Preferred Units), we first allocated net income (loss) in accordance with the amount of distributions made for the period by each class, if any. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common share even though cash distributions are not necessarily derived from current or prior period earnings. The remaining net income (loss) is allocated to each class in proportion to the class weighted average number of shares outstanding for the period, as compared to the weighted average number of shares for all classes for the period. Diluted net income (loss) per common share reflects the dilutive effects of the participating securities using the two-class method or the treasury stock method, whichever is more dilutive. They also reflect the effects of the potential

Table of Contents

conversion of the Company's Series A and Series B Preferred Stock (as defined below) using the if converted method, if the effect is dilutive.

Principles of Consolidation

The Company's condensed consolidated financial statements include the accounts of the Company and its subsidiaries. All intercompany balances and transactions have been eliminated.

Use of Estimates

The condensed consolidated financial statements are prepared in conformity with U.S. GAAP, which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, the evaluation of unproved properties for impairment, the fair value of commodity derivative contracts, embedded derivatives and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

Recent Accounting Pronouncements

In August 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-12 "Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities," which changes the recognition and presentation requirements of hedge accounting, including eliminating the requirement to separately measure and report hedge ineffectiveness, and presenting all items that affect earnings in the same income statement line item as the hedged item. The ASU also provides new alternatives for applying hedge accounting. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2018. Early adoption is permitted, and the Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01 "Business Combinations (Topic 805): Clarifying the Definition of a Business," which provides a new framework for determining whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, and the Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In November 2016, the FASB issued ASU 2016-18 “Statement of Cash Flows (Topic 230): Restricted Cash,” which requires companies to include cash and cash equivalents that have restrictions on withdrawal or use in total cash and cash equivalents on the statement of cash flows. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, and the Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In October 2016, the FASB issued ASU 2016-16 “Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory,” which eliminates a current exception in U.S. GAAP to the recognition of the income tax effects of temporary differences that result from intra-entity transfers of non-inventory assets. The intra-entity exception is being eliminated under the ASU. The standard is required to be applied on a modified retrospective basis and will be effective beginning with the first quarter 2018. Early adoption is permitted, and the Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15 “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments”. This ASU is intended to clarify the presentation of cash receipts and payments in specific situations. The amendments in this ASU are effective for financial statements issued for annual periods beginning after December 15, 2017, including interim periods within those annual periods, and early application is permitted. The Company does not anticipate that ASU 2016-15 will have a material effect on its consolidated and condensed financial statements and related disclosures.

Table of Contents

In March 2016, the FASB issued ASU No. 2016-09 “Compensation – Stock Compensaion (Topic 718): Improvements to Employee Share-Based Payment Accounting,” effective for annual and interim periods for public companies beginning after December 15, 2016. ASU 2016-09 changes several aspects of the accounting for share-based payment award transactions including accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, minimum statutory tax withholding requirements and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. The Company adopted ASU 2016-09 as of the quarter ended March 31, 2017 on a retrospective basis. Adoption of this guidance affected the statement of cash flows as of September 30, 2016 as follows (in thousands):

Increase in net cash provided by operating activities of approximately $1,896

Increase in net cash used in financing activities of approximately $1,896

In February 2016, the FASB issued ASU No. 2016-02 “Leases (Topic 842),” effective for annual and interim periods for public companies beginning after December 15, 2018, with a modified retrospective approach to be used for implementation. The standard updates the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for all leases with lease terms of more than 12 months. The lease liability represents the discounted obligation to make future minimum lease payments and corresponding right-of-use asset on the balance sheet for most leases. Recognition, measurement and presentation of expenses and cash flows arising from a lease will depend on classification as a finance or operating lease. The Company has several operating leases as further discussed in Note 16, “Commitments and Contingencies,” which will be impacted by the new rules under this standard. The Company will not early adopt this standard, and will apply the revised lease rules for our interim and annual reporting periods starting January 1, 2019. The Company is currently evaluating the impact of these rules on its financial statements and has started the assessment process by evaluating the population of leases under the revised definition. The adoption of this standard will result in an increase in the assets and liabilities on the Company’s consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” In March, April, and May of 2016, the FASB issued rules clarifying several aspects of the new revenue recognition standard. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new standard also requires more detailed disclosures related to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The Company will not early adopt the standard although early adoption is permitted. The Company’s expectation is to apply the modified retrospective approach. As part of the assessment, the Company has formed an implementation work team, completed trainings on the new revenue recognition model and gathered a representative sample of material revenue contracts covering current revenue streams for which we are currently evaluating the impact under the new standard. The Company is currently collecting all remaining contracts and evaluating the impacts to its consolidated financial statements under the revised standards. In addition, the Company is evaluating the impacts of significant historical transactions under the new standard. As of September 30, 2017, the Company determined that the deferred gains recorded under the Carnero Gathering Disposition and Carnero Processing Disposition (defined below in Note 11, “Related Party Transactions”) could be de-recognized under the new standard. Under the modified retrospective approach, we would adjust the balance of accumulated deficit on January 1, 2018.

Note 3. Acquisitions and Divestitures

Our acquisitions are accounted for under the acquisition method of accounting in accordance with ASC Topic 805, “Business Combinations”. A business combination may result in the recognition of a gain or goodwill based on the measurement of the fair value of the assets acquired at the acquisition date as compared to the fair value of consideration transferred, adjusted for purchase price adjustments. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that

Table of Contents

existed as of the acquisition dates. The initial accounting for the Comanche Acquisition, described below, is not yet complete for the oil and gas properties, general property, asset retirement obligations, and potential intangible assets. The Company is currently in the process of evaluating the final purchase price allocation based on the fair value of all assets and liabilities acquired in the Comanche Acquisition. The results of operations of the properties acquired in our acquisitions have been included in the condensed consolidated financial statements since the closing dates of the acquisitions.

Javelina Disposition

On September 19, 2017, the Company, through its wholly owned subsidiary, SN Cotulla Assets, LLC ("SN Cotulla"), sold approximately 68,000 undeveloped net acres located in the Eagle Ford Shale in LaSalle and Webb Counties, Texas to Vitruvian Exploration IV, LLC for approximately $105 million in cash, after preliminary closing adjustments ("the Javelina Disposition"). Consideration received from the Javelina Disposition was based on an August 1, 2017 effective date and is subject to normal and customary post-closing adjustments. The Company did not record any gains or losses as a result of the Javelina Disposition.

Marquis Disposition

On June 15, 2017, the Company, through its wholly owned subsidiary, SN Marquis LLC, sold approximately 21,000 net acres primarily located in the Eagle Ford Shale in Fayette and Lavaca Counties, Texas to Lonestar Resources US, Inc. ("Lonestar") for approximately $44 million in cash, after preliminary closing adjustments, and Lonestar Series B Convertible Preferred Stock structured to be converted into 1.5 million shares of Lonestar Class A Common Stock (the "Lonestar Convertible Shares") upon the satisfaction of certain conditions (the "Marquis Disposition"). Consideration received from the Marquis Disposition was based on a January 1, 2017 effective date and is subject to other normal and customary post-closing adjustments. Assets conveyed pursuant to the Marquis Disposition consist of net proved reserves of approximately 2.7 million barrels of oil equivalent ("Boe") (100% developed) and net production of approximately 1,750 Boe per day from 104 gross (65 net) wells. The Company did not record any gains or losses as a result of the Marquis Disposition.

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 approximately $2.1

billion in cash, after preliminary closing adjustments (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 through a $100 million cash contribution from other Company entities) and (ii) SN Maverick paid approximately 13% of the purchase price. In the aggregate, SN UnSub and SN Maverick acquired half of the 49% working interest in the Comanche Assets (approximately 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 total proved undeveloped reserves (PUDs)). Pursuant to the purchase and sale agreement, Gavilan paid 50% of the purchase price and acquired the remaining half of the 49% working interest in and to the Comanche Assets (and approximately 50% of the estimated total PDPs, PDNPs and PUDs). The Comanche Assets are primarily located in the Western Eagle Ford and significantly expanded the Company’s asset base and production. The effective date of the Comanche Acquisition is July 1, 2016. The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved oil and natural gas properties	$ 781,988
Unproved properties	262,677
Other assets acquired	2,751
Fair value of assets acquired	1,047,416
Asset retirement obligations	(8,289)
Fair value of net assets acquired	$ 1,039,127

Table of Contents

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. In particular, with respect to the Comanche Assets, 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 63,000 barrels per day (approximately 14,800 barrels per day net) of crude oil and condensate in 2020 and 430,000 Mcf per day (approximately 101,400 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 and expect to continue to fulfill these obligations based on our anticipated development plan for the Comanche Assets.

Cotulla Disposition

On December 14, 2016, SN Cotulla, a wholly owned subsidiary of the Company, completed the initial closing of the sale of certain oil and gas interests and associated assets located in Dimmit County, Frio County, LaSalle County, Zavala County and McMullen County, Texas (the “Cotulla Assets”) to Carrizo (Eagle Ford) LLC (“Carrizo Eagle Ford”) pursuant to a purchase and sale agreement dated October 24, 2016 by and among SN Cotulla, the Company for the limited purposes set forth therein, Carrizo Eagle Ford and Carrizo Oil and Gas for the limited purposes set forth therein, for a base purchase price of approximately $181.0 million, subject to normal and customary post-closing adjustments (the “Cotulla Disposition”). The effective date of the Cotulla Disposition is June 1, 2016. During 2017, two additional closings occurred and final settlement adjustments were made resulting in total aggregate consideration of approximately $167.4 million.

Typically, sales of oil and gas properties are accounted for as adjustments to oil and natural gas properties with no gain or loss recognized. However, in circumstances where treating a sale like a normal retirement would result in a significant change in the Company’s amortization rate, judgment should be applied. The Company determined that adjustments to capitalized costs for the Cotulla Disposition would cause a significant change in the Company’s amortization rate. Upon the initial closing of the Cotulla Disposition, the Company recorded a gain of approximately $112.3 million. As a result of subsequent closings of the Cotulla Disposition, the Company has recorded additional gains totaling $10.2 million during the nine months ended September 30, 2017. During the third quarter 2017, the Company recorded a reduction of gain on the Cotulla Disposition of approximately $2.1 million related to the final purchase price adjustment of $2.8 million.

Results of Operations and Pro Forma Operating Results

The following unaudited pro forma combined financial information for the three and nine months ended September 30, 2017 and 2016 is based on the historical consolidated financial statements of the Company adjusted to reflect as if the Comanche Acquisition and related financing had occurred on January 1, 2016. The unaudited pro forma combined financial information includes adjustments primarily for revenues and expenses for the acquired properties, depreciation, depletion, amortization and accretion, interest expense and debt issuance cost amortization for acquisition debt, and issuance cost amortization of the acquisition preferred financing. The unaudited pro forma combined financial statements give effect to the events set forth below:

- The Comanche Acquisition completed March 1, 2017.
- The issuance of 500,000 SN UnSub Preferred Units for $500 million to finance a portion of the Comanche Acquisition.
- The borrowing of $173.5 million on a $330 million senior secured reserve based revolving credit facility of SN UnSub (the "SN UnSub Credit Agreement") to finance a portion of the Comanche Acquisition.
- Issuance of 1,455,000 shares of the Company's common stock to certain funds managed or advised by GSO Capital Partners LP ("GSO"), which is an investor in SN UnSub.
- Issuance of 45,000 shares of the Company's common stock to Intrepid Private Equity V-A, LLC ("Intrepid"), which is an investor in SN UnSub.

Table of Contents

- Issuance of warrants to certain funds managed or advised by GSO (the "GSO Funds") to purchase 1,940,000 shares of the Company's common stock at an exercise price of $10 per share.
- Issuance of warrants to Intrepid to purchase 60,000 shares of the Company's common stock at an exercise price of $10 per share.
- Issuance of warrants to Gavilan to purchase 6,500,000 shares of the Company's common stock at an exercise price of $10 per share.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues	$ 184,806	$ 180,298	$ 538,382	$ 502,065
Net loss attributable to common stockholders	$ (57,205)	$ (113,626)	$ (31,170)	$ (551,445)
Net loss per common share, basic and diluted	$ (0.74)	$ (1.57)	$ (0.61)	$ (7.70)

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Company would have reported had the Comanche Acquisition and related financings been completed as of the dates set forth in this unaudited pro forma combined financial information and should not be taken as indicative of the Company's future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Post-Acquisition Operating Results

The amounts of revenue and excess of revenues over direct operating expenses included in the Company's condensed consolidated statements of operations for the nine months ended September 30, 2017 for the Comanche Acquisition are shown in the table that follows. Direct operating expenses include lease operating expenses and production and ad valorem taxes (in thousands):

	Nine Months Ended September 30, 2017
Revenues	$ 161,553
Excess of revenues over direct operating expenses	$ 82,243

Note 4. Cash and Cash Equivalents

As of September 30, 2017 and December 31, 2016, cash and cash equivalents consisted of the following (in thousands):

	September 30, 2017	December 31, 2016
Cash at banks	$ 125,298	$ 58,269
Money market funds	48,930	443,648
Total cash and cash equivalents	$ 174,228	$ 501,917

Note 5. Oil and Natural Gas Properties

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

Table of Contents

properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantity of proved reserves.

Full Cost Ceiling Test—Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and natural gas properties are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. In accordance with SEC rules, the oil and natural gas prices used to calculate the full cost ceiling are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements (the “SEC price”). Prices are adjusted for “basis” or location differentials. Prices are held constant over the life of the reserves. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling. During the three and nine month periods ended September 30, 2017, the Company did not record a full cost ceiling test impairment. While there is a possibility that the Company will incur impairments to our full cost pool in 2017, factors impacting the full cost ceiling test impairment calculation in future periods have not yet been determined. Based upon the NYMEX first-day-of-the-month prices for October 2017, along with the NYMEX WTI forward-looking price deck for November and December 2017, the Company estimates the average 12 month trailing first-day-of-the-month prices ending December 31, 2017 to increase from the current quarter ended.

Costs associated with unproved properties and properties under development, including costs associated with seismic data, leasehold acreage and the current drilling of wells, are excluded from the full cost amortization base until the properties have been evaluated. 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 when management determines that a project area has been evaluated through drilling operations or a thorough geologic evaluation, the project area is transferred into the full cost pool subject to amortization. The Company assesses the carrying value of its unproved properties that are not subject to amortization for impairment periodically. If the results of an assessment indicate that the properties are impaired, the amount of the asset impaired is added to the full cost pool subject to both periodic amortization and the ceiling test.

Note 6. Long Term Debt

Long-term debt on September 30, 2017 consisted of $1.15 billion principal amount of 6.125% senior notes (consisting of $850 million in Original 6.125% Notes (defined below) and $300 million in Additional 6.125% Notes (defined below), which were issued at a premium to face value of $2.3 million), maturing on January 15, 2023, $600 million principal amount of 7.75% senior notes (consisting of $400 million in Original 7.75% Notes (defined below) and $200 million in Additional 7.75% Notes (defined below), which were issued at a discount to face value of $7.0 million), maturing on June 15, 2021, $175.5 million related to the SN UnSub Credit Agreement, and $4.3 million related to 4.59% non-recourse subsidiary term loan due 2022 (the “Non-Recourse Subsidiary Term Loan”).

15

Table of Contents

As of September 30, 2017 and December 31, 2016, the Company's long term debt consisted of the following:

	Interest Rate	Maturity Date	Amount Outstanding (in thousands) as of September 30, 2017	December 31, 2016
Second Amended and Restated Credit Agreement	Variable	June 30, 2019	$ —	$ —
SN UnSub Credit Agreement	Variable	March 1, 2022	175,500	—
7.75% Senior Notes	7.75%	June 15, 2021	600,000	600,000
4.59% Non-Recourse Subsidiary Term Loan	4.59%	August 31, 2022	4,250	—
6.125% Senior Notes	6.125%	January 15, 2023	1,150,000	1,150,000
			1,929,750	1,750,000
Unamortized discount on Additional 7.75% Notes			(3,352)	(4,030)
Unamortized premium on Additional 6.125% Notes			1,427	1,629
Unamortized debt issuance costs			(49,815)	(34,832)
Total long-term debt			$ 1,878,010	$ 1,712,767

The components of interest expense are (in thousands):

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Interest on Senior Notes	$ (29,234)	$ (29,234)	$ (87,703)	$ (87,704)
Interest on SN UnSub credit agreement	(2,356)	—	(5,411)	—
Interest expense and commitment fees on Second Amended and Restated Credit Agreement	(667)	(429)	(1,606)	(1,181)
Amortization of debt issuance costs	(3,270)	(1,975)	(9,476)	(5,865)
Amortization of discount on Additional 7.75% Notes	(226)	(226)	(678)	(677)
Amortization of premium on Additional 6.125% Notes	67	67	202	202
Total interest expense	$ (35,686)	$ (31,797)	$ (104,672)	$ (95,225)

Credit Facility

Second Amended and Restated Credit Agreement:

On June 30, 2014, the Company, as borrower, and certain of its operating subsidiaries, as loan parties, entered into a revolving credit facility represented by a $1.5 billion Second Amended and Restated Credit Agreement with Royal Bank of Canada, as the administrative agent and collateral agent, and the lenders party thereto (together with all subsequent amendments, the "Second Amended and Restated Credit Agreement"). The Second Amended and Restated Credit Agreement provides for the issuance of letters of credit, limited in the aggregate to the lesser of $80 million and the total availability thereunder. As of September 30, 2017, there were no borrowings and no letters of credit outstanding under the Second Amended and Restated Credit Agreement, which had a borrowing base of $350 million and aggregate elected commitments of $300 million. Availability under the Second Amended and Restated Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base and aggregate elected commitment amount. All of the $300 million aggregate elected commitment amount was available for future revolver borrowings as of September 30, 2017.

The Second Amended and Restated Credit Agreement matures on June 30, 2019. The borrowing base under the Second Amended and Restated Credit Agreement is redetermined semi-annually by the lenders based on, among other things, an evaluation of the Company's and its restricted subsidiaries' oil and natural gas reserves. Semi-annual redeterminations of the borrowing base are generally scheduled to occur on or before April 1 and October 1 of each year. The next regularly scheduled borrowing base redetermination is expected to occur in the fourth quarter 2017. The borrowing base is also subject to, among other things, (i) automatic reduction by 25% of the amount of any issuance of high yield debt and second lien debt, subject to certain exceptions, (ii) interim redetermination at the election of the Company once between each scheduled redetermination, (iii) interim redetermination at the election of a majority of the

Table of Contents

lenders once between each scheduled redetermination, and (iv) if the required lenders so direct, in connection with asset sales and swap terminations during the period since the most recent borrowing base determination with a combined borrowing base value of more than 10% of the value of the proved developed oil and gas properties included in the most recent reserve report, a reduction in an amount equal to the borrowing base value, as determined by the administrative agent in its reasonable judgment, of such assets and swaps.

The Company's obligations under the Second Amended and Restated Credit Agreement are guaranteed by all of the Company's existing and future subsidiaries and are secured by a first priority lien on substantially all of the Company's assets and the assets of its existing and future subsidiaries, including a first priority lien on all ownership interests in existing and future subsidiaries, in each case, subject to customary exceptions; provided, however, that the guarantee and first priority lien requirements do not extend to existing and future subsidiaries designated as "unrestricted subsidiaries," including SN UnSub.

At the Company's election, interest on borrowings under the Second Amended and Restated Credit Agreement may be calculated based on an alternate base rate ("ABR") or an adjusted Eurodollar (LIBOR) rate, plus an applicable margin. The applicable margin varies from 1.00% to 2.00% for ABR borrowings and from 2.00% to 3.00% for Eurodollar (LIBOR) borrowings and letters of credit, if any, depending on the Company's utilization of the borrowing base. The Company is also required to pay a commitment fee of 0.50% per annum on any unused aggregate elected commitment amount. Interest on ABR borrowings and the commitment fee are generally payable quarterly. Interest on Eurodollar (LIBOR) borrowings are generally payable at the applicable maturity date.

The Second Amended and Restated Credit Agreement contains various affirmative and negative covenants and events of default that limit the Company's ability to, among other things, incur indebtedness, make restricted payments, grant liens, consolidate or merge, dispose of certain assets, make investments, engage in transactions with affiliates, enter into hedge transactions, and make acquisitions. The Second Amended and Restated Credit Agreement also provides for cross default between the Second Amended and Restated Credit Agreement and the other debt (including debt under the 6.125% Notes and the 7.75% Notes) and obligations in respect of hedging agreements (on a mark-to-market basis), of the Company and its restricted subsidiaries, in an aggregate principal amount in excess of $10 million. Furthermore, the Second Amended and Restated Credit Agreement contains financial covenants that require the Company to satisfy the following tests: (i) current assets plus undrawn borrowing capacity on the Second Amended and Restated Credit Agreement to current liabilities of at least 1.0 to 1.0 as of the last day of each fiscal quarter, and (ii) net first lien debt (defined as the excess of first lien debt over cash) to consolidated last twelve months EBITDA of not greater than 2.0 to 1.0 as of the last day of any fiscal quarter. As of September 30, 2017, the Company was in compliance with the covenants of the Second Amended and Restated Credit Agreement.

From time to time, the agents, arrangers, book runners and lenders under the Second Amended and Restated Credit Agreement and their affiliates have provided, and may provide in the future, investment banking, commercial lending, hedging and financial advisory services to the Company and its affiliates in the ordinary course of business, for which they have received, or may in the future receive, customary fees and commissions for these transactions.

SN UnSub Credit Agreement

On March 1, 2017, SN UnSub, as borrower, entered into a credit agreement for a $500 million revolving credit facility with JP Morgan Chase Bank, N.A. as the administrative agent and the lenders party thereto with a maturity date of March 1, 2022 (the “SN UnSub Credit Agreement”). The initial borrowing base amount under the SN UnSub Credit Agreement was $330 million. Additionally, the SN UnSub Credit Agreement provides for the issuance of letters of credit, generally limited in the aggregate to the lesser of $50 million and the total availability under the borrowing base. Availability under the SN UnSub Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base, which is subject to periodic redetermination. As of September 30, 2017, there were approximately $175.5 million of borrowings and no letters of credit outstanding under the SN UnSub Credit Agreement.

Semi-annual redeterminations of the borrowing base are generally scheduled to occur in April and October of each year, with the initial redetermination in May 2017. On May 8, 2017, the borrowing base of the SN UnSub Credit Agreement was reaffirmed at $330 million in conjunction with the spring redetermination. The next regularly scheduled borrowing base redetermination is expected in the fourth quarter 2017. In addition, the borrowing base is subject to interim redetermination at the request of SN UnSub or the lenders based on, among other things, the lenders’ evaluation of SN UnSub’s and its subsidiaries’ oil and natural gas reserves. The borrowing base is also subject to reduction by 25%

of the amount of certain junior debt issuances other than the first $200 million of such debt and by reductions as a result of hedge terminations and asset dispositions that exceed 5% of the then-effective borrowing base, in addition to other customary adjustments.

The obligations under the SN UnSub Credit Agreement are guaranteed by all of SN UnSub's existing and future subsidiaries and secured by a first priority lien on substantially all of SN UnSub's assets and the assets of SN UnSub's existing and future subsidiaries, including a first priority lien on all ownership interests in existing and future subsidiaries as well as a pledge of equity interests in SN UnSub held by SN EF UnSub Holdings, LLC ("SN UnSub Holdings") and SN EF UnSub GP, LLC, the general partner of SN UnSub (the "SN UnSub General Partner"), in each case, subject to customary exceptions; provided, however, that the guarantee and first priority lien requirements do not extend to existing and future subsidiaries of SN UnSub designated as "unrestricted subsidiaries." As of September 30, 2017, SN UnSub had no subsidiaries.

At SN UnSub's election, borrowings under the SN UnSub Credit Agreement may be made on an ABR or a Eurodollar rate basis, plus an applicable margin. The applicable margin varies from 1.75% to 2.75% for ABR borrowings and from 2.75% to 3.75% for Eurodollar borrowings, depending on the utilization of the borrowing base. In addition, SN UnSub is also required to pay a commitment fee on the amount of any unused commitments at a rate of 0.50% per annum. Interest on ABR borrowings and the commitment fee are generally payable quarterly. Interest on Eurodollar borrowings are generally payable at the applicable maturity date.

The SN UnSub Credit Agreement contains various affirmative and negative covenants and events of default that limit SN UnSub's ability to, among other things, incur indebtedness, make restricted payments, grant liens, consolidate or merge, dispose of certain assets, make certain investments, engage in transactions with affiliates, enter into and maintain hedge transactions and make certain acquisitions.

The SN UnSub Credit Agreement provides for an event of default upon a change of control and cross default between the SN UnSub Credit Agreement and other indebtedness of SN UnSub in an aggregate principal amount exceeding $25 million. Additionally, the SN UnSub Credit Agreement contains "separateness" covenants that require SN UnSub to comply with certain corporate formalities and transact with affiliates on an arm's length basis. Furthermore, the SN UnSub Credit Agreement contains financial covenants that require SN UnSub to satisfy certain specified financial ratios, including the following tests: (i) a current assets plus undrawn borrowing capacity on the SN UnSub Credit Agreement to current liabilities ratio of at least 1.0 to 1.0 as of the last day of each fiscal quarter and (ii) a net debt to consolidated EBITDA ratio of not greater than 4.0 to 1.0 for each test period, in each case commencing with the fiscal quarter ending June 30, 2017. As of September 30, 2017, the Company was in compliance with the covenants of the SN UnSub Credit Agreement.

From time to time, the agents, arrangers, book runners and lenders under the SN UnSub Credit Agreement and their affiliates have provided, and may provide in the future, investment banking, commercial lending, hedging and financial advisory services to SN UnSub and its affiliates in the ordinary course of business, for which they have received, or may in the future receive, customary fees and commissions for these transactions.

7.75% Senior Notes Due 2021

On June 13, 2013, we completed a private offering of $400 million in aggregate principal amount of the Company's 7.75% senior notes that will mature on June 15, 2021 (the "Original 7.75% Notes"). Interest on the notes is payable on June 15 and December 15 of each year. We received net proceeds from this offering of approximately $388 million, after deducting initial purchasers' discounts and offering expenses, which we used to repay outstanding indebtedness at the time. The Original 7.75% Notes are senior unsecured obligations and are guaranteed on a joint and several senior unsecured basis by, with certain exceptions, substantially all of our existing and future subsidiaries.

On September 18, 2013, we issued an additional $200 million in aggregate principal amount of our 7.75% senior notes due 2021 (the "Additional 7.75% Notes" and, together with the Original 7.75% Notes, the "7.75% Notes") in a private offering at an issue price of 96.5% of the principal amount of the Additional 7.75% Notes. We received net proceeds of $188.8 million (after deducting the initial purchasers' discounts and offering expenses of $4.2 million) from the sale of the Additional 7.75% Notes. The Company also received cash for accrued interest from June 13, 2013 through the date of issuance of $4.1 million, for total net proceeds of $192.9 million from the sale of the Additional 7.75% Notes. The Additional 7.75% Notes were issued under the same indenture as the Original 7.75% Notes, and are,

Table of Contents

therefore, treated as a single class of securities under the indenture. We used the net proceeds from the offering to partially fund our acquisition of contiguous acreage in McMullen County, Texas with 13 gross producing wells completed in October 2013, a portion of the 2013 and 2014 capital budgets and for general corporate purposes.

The 7.75% Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured indebtedness. The 7.75% Notes rank senior in right of payment to our future subordinated indebtedness. The 7.75% Notes are effectively junior in right of payment to all of our existing and future secured debt (including under our Second Amended and Restated Credit Agreement) to the extent of the value of the assets securing such debt. The 7.75% Notes are fully and unconditionally guaranteed (except for customary release provisions) on a joint and several senior unsecured basis by the subsidiary guarantors party to the indenture governing the 7.75% Notes. To the extent set forth in the indenture governing the 7.75% Notes, certain of our subsidiaries will be required to fully and unconditionally guarantee the 7.75% Notes on a joint and several senior unsecured basis in the future.

The indenture governing the 7.75% Notes, among other things, restricts our ability and our restricted subsidiaries' ability to: (i) incur, assume, or guarantee additional indebtedness or issue certain types of equity securities; (ii) pay distributions on, purchase or redeem shares or purchase or redeem subordinated debt; (iii) make certain investments; (iv) enter into certain transactions with affiliates; (v) create or incur liens on their assets; (vi) sell assets; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) restrict distributions or other payments from the Company's restricted subsidiaries; and (ix) designate subsidiaries as unrestricted subsidiaries.

We have the option to redeem all or a portion of the 7.75% Notes at any time after June 15, 2017 at the applicable redemption prices specified in the indenture plus accrued and unpaid interest. In addition, we may be required to repurchase the 7.75% Notes upon a change of control or if we sell certain of our assets.

On July 18, 2014, we completed an exchange offer of $600 million aggregate principal amount of the 7.75% Notes that had been registered under the Securities Act of 1933, as amended (the "Securities Act"), for an equal amount of the 7.75% Notes that had not been registered under the Securities Act.

6.125% Senior Notes Due 2023

On June 27, 2014, the Company completed a private offering of $850 million in aggregate principal amount senior unsecured 6.125% notes due 2023 (the "Original 6.125% Notes"). Interest on the notes is payable on each July 15 and January 15. The Company received net proceeds from this offering of approximately $829 million, after deducting initial purchasers' discounts and estimated offering expenses, which the Company used to repay all of the $100 million in borrowings outstanding under its previous credit facility and to finance a portion of the purchase price of the our acquisition of 106,000 net contiguous acres in Dimmit, LaSalle and Webb Counties, Texas (the "Catarina

Acquisition"). We used the remaining proceeds from the offering to fund a portion of the remaining 2014 capital budget and for general corporate purposes. The Original 6.125% Notes are the senior unsecured obligations of the Company and are guaranteed on a joint and several senior unsecured basis by, with certain exceptions, substantially all of the Company's existing and future subsidiaries.

On September 12, 2014, we issued an additional $300 million in aggregate principal amount of our 6.125% senior notes due 2023 (the "Additional 6.125% Notes" and, together with the Original 6.125% Notes, the "6.125% Notes" and, together with the 7.75% Notes, the "Senior Notes") in a private offering at an issue price of 100.75% of the principal amount of the Additional 6.125% Notes. We received net proceeds of $295.9 million, after deducting the initial purchasers' discounts, adding premiums to face value of $2.3 million and deducting estimated offering expenses of $6.4 million. The Company also received cash for accrued interest from June 27, 2014 through the date of the issuance of $3.8 million, for total net proceeds of $299.7 million from the sale of the Additional 6.125% Notes. The Additional 6.125% Notes were issued under the same indenture as the Original 6.125% Notes, and are, therefore, treated as a single class of securities under the indenture. We used a portion of the net proceeds from the offering to fund a portion of the 2014 capital budget and used the remainder of the net proceeds to fund a portion of the 2015 capital budget, and for general corporate purposes.

The 6.125% Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured indebtedness. The 6.125% Notes rank senior in right of payment to the Company's future subordinated indebtedness. The 6.125% Notes are effectively junior in right of payment to all of the Company's existing and future secured debt (including under the Second Amended and Restated Credit Agreement) to the extent of the value

Table of Contents

of the assets securing such debt. The 6.125% Notes are fully and unconditionally guaranteed (except for customary release provisions) on a joint and several senior unsecured basis by the subsidiary guarantors party to the indenture governing the 6.125% Notes. To the extent set forth in the indenture governing the 6.125% Notes, certain of our subsidiaries will be required to fully and unconditionally guarantee the 6.125% Notes on a joint and several senior unsecured basis in the future.

The indenture governing the 6.125% Notes, among other things, restricts our ability and our restricted subsidiaries' ability to: (i) incur, assume or guarantee additional indebtedness or issue certain types of equity securities; (ii) pay distributions on, purchase or redeem shares or purchase or redeem subordinated debt; (iii) make certain investments; (iv) enter into certain transactions with affiliates; (v) create or incur liens on their assets; (vi) sell assets; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) restrict distributions or other payments from the Company's restricted subsidiaries; and (ix) designate subsidiaries as unrestricted subsidiaries.

The Company has the option to redeem all or a portion of the 6.125% Notes, at any time on or after July 15, 2018 at the applicable redemption prices specified in the indenture plus accrued and unpaid interest. The Company may also redeem the 6.125% Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make whole premium, together with accrued and unpaid interest and additional interest, if any, to the redemption date, at any time prior to July 15, 2018. The Company may also be required to repurchase the 6.125% Notes upon a change of control or if we sell certain Company assets.

On February 27, 2015, we completed an exchange offer of $1.15 billion aggregate principal amount of the 6.125% Notes that had been registered under the Securities Act for an equal amount of the 6.125% Notes that had not been registered under the Securities Act.

Pursuant to tripartite agreements by and among the Company, U.S. Bank National Association ("U.S. Bank") and Delaware Trust Company ("Delaware Trust"), effective May 20, 2016, U.S. Bank resigned as the Trustee, Notes Custodian, Registrar and Paying Agent ("Trustee") under the indentures of the Senior Notes and Delaware Trust was appointed as successor Trustee. No other changes to the indentures for the 6.125% Notes or the 7.75% Notes were made at the time of the change in Trustee.

Note 7. Derivative Instruments

To reduce the impact of fluctuations in oil, natural gas, and NGL prices on the Company's business and results of operations, 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. The derivative contracts may include fixed-for-floating 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-for-floating price swaps by agreeing to expand the notional quantity hedged or extend the notional quantity settlement period under a fixed-for floating price swap at the counterparty's election on a designated date.

These hedging activities, which are governed by the terms of our Second Amended and Restated Credit Agreement and the SN UnSub Credit Agreement, as applicable, 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 lenders, or affiliates of lenders, to our Second Amended and Restated Credit Agreement or SN UnSub Credit Agreement are collateralized by the assets securing our Second Amended and Restated Credit Agreement or SN UnSub Credit Agreement, as applicable, and, therefore, do not currently require the posting of cash collateral. Our existing derivatives with non-lender counterparties, as designated under the Second Amended and Restated Credit Agreement and SN UnSub Credit Agreement, are unsecured and do not require the posting of cash collateral. It is never the Company's intention to enter into derivative contracts for speculative trading purposes. In connection with the closing

Table of Contents

of the Comanche Acquisition, we hedged a portion of projected future production attributable to the Comanche Assets, using hedge transactions that are consistent with our current hedging strategy.

All of our derivatives are accounted for as mark-to-market activities. Under ASC 815, “Derivatives and Hedging,” these instruments are recorded on the condensed consolidated balance sheets at fair value as either short term or long term assets or liabilities based on their anticipated settlement date. The Company nets derivative assets and liabilities by commodity for counterparties where a legal right to such offset exists. Changes in the derivatives’ fair values are recognized in current earnings since the Company has elected not to designate its current derivative contracts as cash flow hedges for accounting purposes.

The following table presents derivative positions for the periods indicated as of September 30, 2017:

	October 1 - December 31, 2017	2018	2019	2020
Oil positions:				
Fixed-for-floating price swaps (NYMEX WTI):				
Hedged volume (Bbls)	1,775,000	7,391,124	3,149,000	381,000
Average price ($/Bbl)	$ 52.76	$ 52.56	$ 51.91	$ 53.52
Call swaptions (NYMEX WTI):				
Option volume (Bbls)	-	730,000	730,000	-
Average price ($/Bbl)	$ -	$ 51.38	$ 55.00	$ -
Collars (NYMEX WTI):				
Hedged volume (Bbls)	184,000	-	-	-
Average floor price ($/Bbl)	$ 45.00	$ -	$ -	$ -
Average ceiling price ($/Bbl)	$ 62.00	$ -	$ -	$ -
Natural gas positions:				
Fixed-for-floating price swaps (NYMEX Henry Hub):				
Hedged volume (MMBtu)	14,525,300	68,818,146	17,644,000	2,361,000
Average price ($/MMBtu)	$ 3.14	$ 3.04	$ 2.90	$ 2.82

The following table sets forth a reconciliation of the changes in fair value of the Company’s commodity derivatives for the nine months ended September 30, 2017 and the year ended December 31, 2016 (in thousands):

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
Beginning fair value of commodity derivatives	$ (35,014)	$ 178,283
Net gains (losses) on crude oil derivatives	31,806	(47,389)
Net gains (losses) on natural gas derivatives	24,903	(30,307)
Net settlements on derivative contracts:		
Oil	(16,448)	(135,491)
Natural gas	1,716	(24,657)
Net premiums on derivative contracts:		
Oil	—	24,547
Ending fair value of commodity derivatives	$ 6,963	$ (35,014)

Embedded Derivatives

The Company has entered into contracts for the purchase of sand and coiled tubing that contain provisions that must be bifurcated from the contract and valued as derivatives. The embedded derivatives are valued using a Monte Carlo model which utilizes observable inputs, including the NYMEX WTI oil price and NYMEX Henry Hub natural gas price at various points in time. The Company has marked these derivatives to market as of September 30, 2017, and incurred an approximate $2.1 million gain for the nine months ended September 30, 2017 as a result. Any gains or

Table of Contents

losses related to embedded derivatives are recorded as a component of other income (expense) in the consolidated statement of operations.

The following table sets forth a reconciliation of the changes in fair value of the Company's embedded derivatives for the nine months ended September 30, 2017 (in thousands):

	September 30, 2017
Beginning fair value of embedded derivatives	$ —
Initial fair value of embedded derivatives	—
Gain on embedded derivatives	2,052
Ending fair value of embedded derivatives	$ 2,052

Balance Sheet Presentation

The Company nets derivative assets and liabilities by commodity for counterparties where legal right to such netting exists. Therefore, the Company's derivatives are presented on a net basis as "Fair value of derivative instruments" on the condensed consolidated balance sheets. The following information summarizes the gross fair values of derivative instruments, presenting the impact of netting the derivative assets and liabilities on the Company's condensed consolidated balance sheets (in thousands):

	September 30, 2017		
	Gross Amount of Recognized Assets and Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 14,708	$ (3,330)	$ 11,378
Long-term asset	10,108	(1,166)	8,942
Total asset	$ 24,816	$ (4,496)	$ 20,320
Offsetting Derivative Liabilities:			
Current liability	$ 7,015	$ (3,330)	$ 3,685
Long-term liability	8,786	(1,166)	7,620
Total liability	$ 15,801	$ (4,496)	$ 11,305

	December 31, 2016		
	Gross Amount	Gross Amounts	Net Amounts

	of Recognized Assets and Liabilities	Offset in the Consolidated Balance Sheets	Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 844	$ (844)	$ —
Long-term asset	1,426	(1,426)	—
Total asset	$ 2,270	$ (2,270)	$ —
Offsetting Derivative Liabilities:			
Current liability	$ 32,622	$ (844)	$ 31,778
Long-term liability	4,662	(1,426)	3,236
Total liability	$ 37,284	$ (2,270)	$ 35,014

Note 8. Investments

On June 15, 2017, the Company received 1,500,000 shares of Lonestar's Series B Convertible Preferred Stock as part of the consideration for the Marquis Disposition. The Series B Convertible Preferred Stock is convertible into Lonestar Convertible Shares. The Lonestar Convertible Shares are accounted for by the Company as investments in equity securities measured at fair value in the consolidated balance sheets at the end of each reporting period. The

Table of Contents

Company recorded losses related to the investment in the Lonestar Convertible Shares for the nine months ended September 30, 2017 of approximately $0.7 million. Any gains or losses related to the investment in the Lonestar Convertible Shares are recorded as a component of other income (expense) in the consolidated statement of operations.

On June 14, 2017, SN Catarina, LLC (“SN Catarina”), a wholly owned subsidiary of the Company, completed the sale of its 10% undivided interest in the Silver Oak II Gas Processing Facility in Bee County, Texas (the “SOII Facility”) to a subsidiary of Targa Resources Corp. (“Targa”) with an effective date of June 1, 2017 for $12.5 million of cash (the “SOII Disposition”). Prior to the SOII Disposition, the Company had invested $12.5 million in the SOII Facility. No gain or loss was recorded on the SOII Disposition. The Company recorded earnings of approximately $779 thousand from its equity interest in the SOII Facility for the period from January 1, 2017 through June 1, 2017, the effective date of the transaction.

On November 22, 2016, a subsidiary of the Company purchased 2,272,727 of SNMP’s common units for $25.0 million in a private placement. As of September 30, 2017, this ownership represented approximately 15.4% of SNMP’s outstanding common units. Rather than accounting for the investment under the equity method, the Company elected the fair value option to account for its interest in SNMP. The Company records the equity investment in SNMP at fair value at the end of each reporting period. The Company recorded losses related to the investment in SNMP for the nine months ended September 30, 2017 of approximately $1.3 million. In addition, the Company has recorded dividend income of approximately $3.0 million for the nine months ended September 30, 2017 from the quarterly distributions made by SNMP. Any gains or losses and dividend income related to the investment in SNMP are recorded as a component of other income (expense) in the consolidated statement of operations.

Note 9. Fair Value of Financial Instruments

Measurements of fair value of derivative instruments are classified according to the fair value hierarchy, which prioritizes the inputs to the valuation techniques used to measure fair value. Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that can be valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). The valuation models used to value derivatives associated with the Company's oil and natural gas production are primarily industry standard models that consider various inputs including (a) quoted forward prices for commodities, (b) time value and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although third-party quotes are utilized to assess the reasonableness of the prices and valuation techniques, there is not sufficient corroborating evidence to support classifying these assets and liabilities as Level 2. As of September 30, 2017, the Company had no financial instruments classified as Level 3.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Table of Contents

Fair Value on a Recurring Basis

The following tables set forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2017 and December 31, 2016 (in thousands):

	As of September 30, 2017			
	Active Market for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents:				
Money market funds	$ 48,930	$ —	$ —	$ 48,930
Investments:				
Investment in SNMP	25,568	—	—	25,568
Investment in Lonestar	5,265	—	—	5,265
Oil derivative instruments:				
Swaps	—	10,636	—	10,636
Call swaptions	—	(4,175)	—	(4,175)
Collars	—	35	—	35
Gas derivative instruments:				
Swaps	—	467	—	467
Embedded derivative instruments:				
Sand and coiled tubing contracts	—	2,052	—	2,052
Total	$ 79,763	$ 9,015	$ —	$ 88,778

	As of December 31, 2016			
	Active Market for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents:				
Money market funds	$ 443,648	$ —	$ —	$ 443,648
Equity investment:				
Investment in SNMP	26,818	—	—	26,818
Oil derivative instruments:				
Swaps	—	(8,291)	—	(8,291)
Collars	—	(572)	—	(572)
Gas derivative instruments:				
Swaps	—	(26,151)	—	(26,151)
Total	$ 470,466	$ (35,014)	$ —	$ 435,452

Financial Instruments: The Level 1 instruments presented in the tables above consist of money market funds and time deposits included in cash and cash equivalents on the Company's condensed consolidated balance sheets at September 30, 2017 and December 31, 2016. The Company's money market funds and time deposits represent cash equivalents backed by the assets of high-quality banks and financial institutions. The Company identified the money market funds and time deposits as Level 1 instruments due to the fact that these instruments have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments. In addition, the Level 1 instruments include the Company's equity investment in common units of SNMP as further discussed in Note 8, "Investments." The investment in SNMP is being accounted for under the fair value option, included in investments on the Company's balance sheet as of September 30, 2017. The Company identified the common units in SNMP as a Level 1 instruments due to the fact that SNMP is a publicly traded company on the NYSE American with daily quoted prices that can be readily obtained. The Level 1 instruments also include the Company's investment in the Series B Convertible Preferred Shares of Lonestar as further discussed in Note 8, "Investments." The investment in the Lonestar Convertible Shares is being accounted for at fair value and included in investments on the Company's balance sheet as of September 30, 2017. The Company identified the Lonestar Convertible Shares as Level

Table of Contents

1 instruments as their underlying share value is the publicly traded value of the Class A Common Units of Lonestar, with daily quoted prices that can be readily obtained on the Nasdaq Global Market exchange.

The Company’s derivative instruments, which currently consist of swaps, call swaptions, and collars, are classified as Level 2 as of September 30, 2017 and December 31, 2016 in the table above. The fair values of the Company’s derivatives are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as forward curves, or can be corroborated from active markets of broker quotes. Swaps and collars generally have observable inputs and they are classified as Level 2. Call swaption derivatives have inputs which are observable, either directly or indirectly, using market data. As of September 30, 2017, the Company believed that substantially all of the inputs required to calculate the fair value of puts are observable in the marketplace throughout the term of these derivative instruments or supported by observable levels at which transactions are executed in the marketplace and are, therefore, classified as Level 2. As of December 31, 2016, the Company believed that substantially all of the inputs required to calculate the fair value of swaps, call swaptions, and collars are observable in the marketplace throughout the term of these derivative instruments or supported by observable levels at which transactions are executed in the marketplace, and are, therefore, classified as Level 2. Derivative instruments are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of the Company’s derivative instruments, but to date has not had a material impact on estimates of fair values. Significant changes in the quoted forward prices for commodities and changes in market volatility generally lead to corresponding changes in the fair value measurement of the Company’s derivative instruments.

There were no commodity derivative instruments classified as Level 3 as of September 30, 2017 or December 31, 2016.

Embedded Derivative: The Company consummated contracts for the purchase of sand and coiled tubing that contain provisions that must be bifurcated from the contract and valued as a derivative. The embedded derivative is valued using a Monte Carlo model which utilizes observable inputs, including the NYMEX WTI oil price and the NYMEX Henry Hub natural gas price at various points in time. The Company believes that substantially all of the inputs required to calculate the embedded derivatives are observable in the marketplace throughout the term of these derivative instruments or supported by observable levels at which transactions are executed in the marketplace, and are, therefore, classified as Level 2 inputs. The Company has marked these derivatives to market as of September 30, 2017, and incurred an approximate $2.1 million gain as a result. The gain is the result of the increase in fair value of the embedded derivatives due to the favorable terms of the contracts compared to future forecasted oil and natural gas commodity prices.

The fair value of the Company’s embedded derivatives classified as Level 2 as of September 30, 2017 was $2.1 million. Changes in the inputs will impact the fair value measurement of the Company's embedded derivative contracts.

Fair Value on a Non Recurring Basis

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. Fair value measurements of assets acquired and liabilities assumed in business combinations are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of acquired properties is based on market and cost approaches. Our purchase price allocation for the Comanche Acquisition is presented in Note 3, "Acquisitions and Divestitures." Liabilities assumed include asset retirement obligations existing at the date of acquisition. Asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligations is presented in Note 10, "Asset Retirement Obligations."

In connection with the exchange agreements entered into by the Company in February, May and August of 2014 with certain holders of the Company's Series A Convertible Perpetual Preferred Stock ("Series A Preferred Stock") and Series B Convertible Perpetual Preferred Stock ("Series B Preferred Stock"), the Company issued common stock according to the conversion rate pursuant to each agreement and additional shares to induce the holders of the preferred stock to convert prior to the date the Company could mandate conversion. In addition, on November 20, 2015, a holder of our Series B Preferred Stock exercised its right to convert 4,500 shares of our Series B Preferred Stock, at the prescribed initial conversion rate of 2.337 shares of common stock per share of Series B Preferred Stock, in exchange for

Table of Contents

10,517 shares of our common stock. The fair value of the common stock issued is based on the price of the Company's common stock on the date of issuance. As there is an active market for the Company's common stock, the Company has designated this fair value measurement as Level 1. A detailed description of the Company's common stock and preferred stock issuances and redemptions is presented in Note 13, "Stockholders' and Mezzanine Equity."

Fair Value of Other Financial Instruments

The carrying amounts of our oil and natural gas receivables, accounts payable and accrued liabilities approximate fair value due to the highly liquid nature of these short-term instruments. The registered 7.75% Notes are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 7.75% Notes was $571.5 million as of September 30, 2017 and was calculated using quoted market prices based on trades of such debt as of that date. The registered 6.125% Notes are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 6.125% Notes was $977.5 million as of September 30, 2017 and was calculated using quoted market prices based on trades of such debt as of that date.

Note 10. Asset Retirement Obligations

The Company's 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. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs. Revisions in estimated liabilities can also include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement.

The changes in the asset retirement obligation for the nine months ended September 30, 2017 and the year ended December 31, 2016 were as follows (in thousands):

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
Abandonment liability, beginning of period	$ 25,087	$ 25,907
Liabilities incurred during period	2,134	1,492
Acquisitions	8,289	219
Divestitures	(3,802)	(4,433)
Revisions	(52)	(172)
Accretion expense	1,922	2,074

Abandonment liability, end of period	$ 33,578	$ 25,087

Note 11. Related Party Transactions

SOG, headquartered in Houston, Texas, is a privately owned full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of several of its affiliates, including the Company, pursuant to existing management services agreements. The Company refers to SOG and its affiliates (but excluding the Company) collectively as the "Sanchez Group." Ana Lee Sanchez Jacobs, an immediate family member of our Executive Chairman of our board of directors (our "Board"), our Chief Executive Officer, our President, and an Executive Vice President of the Company, collectively with such individuals, either directly or indirectly, own 100% the equity interests of SOG; these individuals, as well as Ms. Ana Lee Sanchez Jacobs, are officers of SOG. In addition, Antonio R. Sanchez, Jr. is the sole member of the board of directors of SOG.

The Company does not have any employees. On December 19, 2011, the Company entered into a services agreement with SOG pursuant to which specified employees of SOG provide certain services with respect to the Company's business under the direction, supervision and control of SOG. Pursuant to this arrangement, SOG performs centralized corporate functions for the Company, such as general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals. The Company compensates SOG for the services at a price equal to SOG's cost of providing such services, including all direct costs and indirect administrative and overhead costs (including the allocable portion of salary, bonus, incentive compensation

Table of Contents

and other amounts paid to persons that provide the services on SOG's behalf) allocated in accordance with SOG's regular and consistent accounting practices, including for any such costs arising from amounts paid directly by other members of the Sanchez Group on SOG's behalf or borrowed by SOG from other members of the Sanchez Group, in each case, in connection with the performance by SOG of services on the Company's behalf. The Company also reimburses SOG for sales, use or other taxes, or other fees or assessments imposed by law in connection with the provision of services to the Company (other than income, franchise or margin taxes measured by SOG's net income or margin and other than any gross receipts or other privilege taxes imposed on SOG) and for any costs and expenses arising from or related to the engagement or retention of third-party service providers.

Salaries and associated benefits of SOG employees are allocated to the Company at a fixed rate which is reviewed annually and adjusted, if needed, based on a detailed analysis of actual time spent by the professional staff on Company projects and activities. General and administrative expenses such as office rent, utilities, supplies and other overhead costs, are allocated at the same fixed rate as the SOG employee salaries. Expenses allocated to the Company for general and administrative expenses for the three and nine months ended September 30, 2017 and 2016, are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Administrative fees	$ 6,792	$ 8,028	$ 37,846	$ 28,028
Third-party expenses	1,911	700	5,070	4,357
Total included in general and administrative expenses	$ 8,703	$ 8,728	$ 42,916	$ 32,385

As of September 30, 2017 and December 31, 2016, the Company had a net receivable from SOG and other members of the Sanchez Group of $7.6 million and $6.4 million, respectively, which are reflected as "Accounts receivable—related entities" in the condensed consolidated balance sheets. The net receivable as of September 30, 2017 and December 31, 2016 consists primarily of advances paid related to general and administrative and other costs paid to SOG.

As of September 30, 2017 and December 31, 2016, the Company had a net payable to SNMP of approximately $9.3 million and $9.0 million, respectively, that consists primarily of the accrual for fees associated with the gathering agreement signed with SNMP as part of the Company's sale of SN Catarina's interests in Catarina Midstream, LLC, a wholly owned subsidiary of SN Catarina (the "Western Catarina Midstream Divestiture"), which is reflected in the "Accrued Liabilities - Other" account on the consolidated balance sheets. On June 30, 2017, the gathering agreement was amended to, among other things, provide for an additional, incremental infrastructure fee payable to SNMP of $1.00 per barrel of water delivered by SNMP on or after April 1, 2017 through and including March 31, 2018, with no such fee being payable thereafter, and to eliminate certain late payment fees from SN Catarina to SNMP. On September 1, 2017, SN Catarina entered into an agreement with Seco Pipeline, LLC, ("Seco Pipeline") a wholly owned subsidiary of SNMP, whereby Seco Pipeline transports certain quantities of natural gas on a firm basis for $0.22 per MMBtu delivered on or after September 1, 2017. This agreement had an initial term of one month that expired on September 30, 2017, but the agreement will continue month to month thereafter unless terminated by either party.

Antonio R. Sanchez, III, the son of Antonio R. Sanchez, Jr. and brother of Eduardo A. Sanchez and Patricio D. Sanchez, is the Company's Chief Executive Officer and is a member of the board of directors of both the Company and of the general partner of SNMP ("SNMP GP"). Patricio D. Sanchez, an Executive Vice President of the Company, is the president and chief operating officer of SNMP GP and a director of SNMP GP. Eduardo A. Sanchez, our President, is also a member of the board of directors of SNMP GP. Antonio R. Sanchez, Jr., the Executive Chairman of the Board of the Company, Antonio R. Sanchez, III, Patricio D. Sanchez and Eduardo A. Sanchez all directly or indirectly own certain equity interests in the Company and SNMP. Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, Patricio D. Sanchez and Eduardo A. Sanchez beneficially own approximately 0.63%, 1.79%, 2.15% and 1.78%, respectively, of the SNMP common units outstanding as of September 30, 2017.

Comanche Acquisition

On March 1, 2017, we closed the Comanche Acquisition discussed above and, in connection with the closing, entered into a number of transactions with Gavilan, GSO and the Blackstone Warrantholders (as defined below), which

Table of Contents

are related parties (see Note 3, “Acquisitions and Divestitures”), including (i) the SPA (as defined below) with an investment vehicle owned by the GSO Funds and a controlled affiliate of GSO, (ii) warrant agreements with the Blackstone Warrantholders, (iii) Registration Rights Agreements with the Blackstone Warrantholders and GSO, (iv) the Partnership Agreement with an entity controlled by an affiliate of GSO, and (v) the GP LLC Agreement with a controlled affiliate of GSO (see Note 13, “Stockholders’ and Mezzanine Equity”).

In addition, in connection with the closing of the Comanche Acquisition, we also entered into (i) separate standstill and voting agreements (the “Standstill Agreements”) with the Blackstone Funds (as defined below) and the GSO Funds, respectively, (ii) an eight-year (subject to earlier termination as provided for therein) joint development agreement (the “JDA”) with Gavilan, (iii) a shareholders agreement (the “Shareholders Agreement”) with Gavilan Resources Holdco, LLC (“Gavilan Holdco”), (iv) a management services agreement (the “Management Services Agreement”) with Gavilan Holdco and SN Comanche Manager, LLC (“Manager”), a wholly owned subsidiary of the Company, and (v) certain marketing agreements with Gavilan.

Each Standstill Agreement (i) restricts the ability of each of Blackstone Capital Partners VII L.P. and Blackstone Energy Partners II L.P. (together, the “Blackstone Funds”) and the GSO Funds (and indirectly certain of their affiliates) to take certain actions relating to the acquisition of our securities or assets or participation in our management, (ii) contains a two year lock-up restricting dispositions of the Company’s common stock or the warrants to purchase the Company’s common stock, and (iii) contains an agreement to vote any voting securities of the Company in the same manner as recommended by our Board.

Pursuant to the Shareholders Agreement, Gavilan Holdco has the right, but not the obligation, to appoint one observer representative to be present at all regularly scheduled meetings of the full board of directors of the Company.

The JDA provides for the administration, operation and transfer of the jointly owned Comanche Assets, and further provides for the (i) establishment of an operating committee to control the timing, scope and budgeting of operations on the Comanche Assets (subject to certain exceptions) and (ii) designation of SN Maverick as operator of the Comanche Assets and certain other interests (subject to forfeiture in the event of certain default events); the JDA also provides for mechanics relating to division of assets and operatorship among the parties, contains restrictions on the indirect or direct transfer of the parties’ interests in the Comanche Assets, including certain tag-along rights and rights of first offer provisions, and provides Gavilan with certain drag-along rights in the event of certain sale transactions, subject to certain exceptions and potential alternative structures or asset divisions. For additional information regarding the JDA, see Note 16, “Commitments and Contingencies.”

Pursuant to the Management Services Agreement, the Manager serves as manager of Gavilan Holdco’s business and provides comprehensive general, administrative, business and financial services at a price equal to Manager’s actual cost of providing such services (including an “administrative fee” equal to 2% of SOG’s total G&A costs), continuing until the occurrence of one or more events giving Manager or Gavilan Holdco the right to terminate the agreement. At the closing of the Comanche Acquisition, Gavilan Holdco paid $1.0 million to Manager under the agreement. The

Management Services Agreement provides that Manager may not bill more than $500,000 of G&A costs per month to Gavilan Holdco (subject to reasonable adjustments that are consistent with market terms as a result of an increase in actual G&A costs incurred, and based upon a reasonable allocation of such costs). We also entered into a back-to-back management arrangement between Manager and SOG, on substantially the same terms and conditions as the Management Services Agreement, pursuant to which Manager delegated to SOG, and SOG agreed to perform for and on behalf of Manager, Manager's duties and obligations under such services agreement; Manager is required to remit amounts received directly from Gavilan Holdco to Manager, including the $1.0 million paid at closing to Manager, and to pay SOG the 2% administrative fee referred to above. In addition, we entered into a management services agreement between SOG and SN UnSub pursuant to which SOG serves as manager of SN UnSub's oil and gas properties and provides comprehensive general, administrative, business and financial services at a price equal to SOG's actual cost of providing such services (including an "administrative fee" equal to 2% of SOG's total G&A costs), with an initial term expiring on March 1, 2024 (subject to earlier termination as provided therein), renewing automatically for additional one-year terms thereafter unless either SN UnSub or SOG delivers written notice to the other of its desire not to renew the term at least 180 days prior to such anniversary date. SOG may not bill G&A costs to SN UnSub in excess of $5 million per calendar year until March 1, 2019, or in excess of $10 million per calendar year thereafter.

Pursuant to a crude oil production marketing agreement, a residue gas marketing agreement and a NGL marketing agreement between Gavilan and SN Maverick, Gavilan sells all of its production from the Comanche Assets

Table of Contents

to SN Maverick and SN Maverick purchases all such production from Gavilan, transports and sells such production and remits to Gavilan its proportionate share of the sale proceeds

Production Asset Transaction

On November 22, 2016, SN Cotulla and SN Palmetto, LLC ("SN Palmetto"), wholly owned subsidiaries of the Company, completed the sale of certain non-core producing oil and gas assets, located in South Texas, to SNMP and a subsidiary of SNMP for an adjusted purchase price of approximately $24.2 million in cash (the "Production Asset Transaction"). The Production Asset Transaction includes working interests in 23 producing Eagle Ford wellbores located in Dimmit and Zavala counties in South Texas together with escalating working interests in an additional 11 producing wellbores located in the Palmetto Field in Gonzales County, Texas. The effective date of the Production Asset Transaction is July 1, 2016. The aggregate average working interest percentage initially conveyed for the 11 producing wellbores with escalating working interests was 17.92% per wellbore and, upon January 1 of each subsequent year after the closing until January 1, 2018, the purchaser's working interest will automatically increase in incremental amounts according to the purchase agreement, at which point, the purchaser will own a 47.5% working interest and we will own a 2.5% working interest in each of the wellbores. The Company did not record any gains or losses related to the Production Asset Transaction.

Carnero Processing Disposition

On November 22, 2016, SN Midstream, LLC ("SN Midstream"), a wholly owned subsidiary of the Company, sold its 50% membership interests in Carnero Processing, LLC ("Carnero Processing"), a 50% joint venture with an affiliate of Targa, to SNMP for an initial payment of $55.5 million 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"). The Company accounted for this joint venture as an equity method investment. Prior to the sale, the Company had invested approximately $48.0 million in Carnero Processing. Prior to the Carnero Processing Disposition, the Company recorded losses of approximately $0.1 million from equity investments during 2016. The Company recorded a deferred gain of approximately $7.5 million included in "Other Liabilities" as a result of the firm gas processing agreement that remains between the Company and Targa. This deferred gain will be amortized periodically over the term of this firm gas processing agreement according to volumes processed through the Carnero Processing facility.

SNMP Unit Acquisition

On November 22, 2016, a subsidiary of the Company purchased 2,272,727 common units of SNMP for $25.0 million in a private placement (see Note 8, "Investments").

SNMP Lease Option

On October 6, 2016, the Company and SN Terminal, LLC (“SNT”), a wholly owned subsidiary of the Company, on the one hand, and SNMP, on the other hand, entered into a Purchase and Sale Agreement (the “Lease Option Purchase Agreement”) pursuant to which SNT sold and conveyed to SNMP an option to acquire a ground lease (the “Lease Option”) to which SNT is a party for a tract of land leased from the Calhoun Port Authority in Point Comfort, Texas. In addition, if the Company or any of its affiliates enter into an option to engage in the construction of or participation in a Project (as defined below) and/or receive the benefit of an acreage dedication from an affiliate of the Company relating to a Project, then such option and/or acreage dedication will also be assigned to SNMP, if SNMP exercises the Lease Option. SNMP will pay SNT $1.00 if the Lease Option is exercised, along with $250,000 if SNMP or any other person affiliated with SNMP elects to construct, own or operate a marine crude storage terminal on or within five miles of the Port Comfort lease or participates as an investor in the same, within five miles thereof (a “Project”), or the Company or its affiliates convey an acreage dedication to or an option regarding a Project. On September 11, 2017, the Company, SNT and SNMP entered into an agreement that terminated the Lease Option.

Carnero Gathering Disposition

On July 5, 2016, SN Midstream sold its 50% membership interest in Carnero Gathering, LLC (“Carnero Gathering”), a 50% joint venture with an affiliate of Targa, to SNMP for an initial payment of approximately $37.0 million and the assumption by SNMP of remaining capital commitments to Carnero Gathering, estimated on the

Table of Contents

transaction closing date to be approximately $7.4 million (the "Carnero Gathering Disposition"). The Company accounted for this joint venture as an equity method investment. Prior to the Carnero Gathering Disposition, the Company had invested approximately $26.0 million in Carnero Gathering. As part of the Carnero Gathering Disposition, SNMP is required to pay SN Midstream a monthly earnout based on gas received from SN Catarina at Carnero Gathering's receipt points and gas delivered and processed at the "Raptor Gas Processing Facility," a cryogenic natural gas processing plant owned by Carnero Processing in La Salle County, Texas, for other producers. Prior to the Carnero Gathering Disposition, the Company recorded earnings of approximately $2.3 million from equity investments during 2016. The Company recorded a deferred gain of approximately $8.7 million included in "Other Liabilities" as a result of the firm gas gathering agreement that remains in effect between the Company and Targa and a transportation services agreement between Targa and Carnero Gathering. This deferred gain will be amortized periodically over the term of the firm gas gathering agreement according to volumes delivered through the Carnero Gathering pipelines.

Note 12. Accrued Liabilities and Other Current Liabilities

The following information summarizes accrued liabilities as of September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Capital expenditures	$ 114,591	$ 35,154
Other:		
General and administrative costs	10,126	14,738
Production taxes	4,500	2,396
Ad valorem taxes	8,764	2,756
Lease operating expenses	34,268	23,942
Interest payable	28,508	34,266
Preferred dividends payable	3,987	4,360
Total accrued liabilities	$ 204,744	$ 117,612

The following information summarizes the other payables as of September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Revenue payable	$ 63,327	$ 2,124

Production tax payable	4,667	—
Other	1,166	127
Total other payables	$ 69,160	$ 2,251

The following information summarizes the other current liabilities as of September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Operated prepayment liability	$ 59,703	$ —
Deferred gain on Western Catarina Midstream Divestiture - short term	14,813	14,813
Phantom compensation payable - short term	2,246	7,388
Total other current liabilities	$ 76,762	$ 22,201

Note 13. Stockholders' and Mezzanine Equity

Common Stock Offerings— On May 25, 2017, the Company entered into an equity distribution agreement with Citigroup Global Markets, Inc., BMO Capital Markets Corp., Capital One Securities, Inc., RBC Capital Markets, LLC and SunTrust Robinson Humphrey, Inc. and filed with the SEC a prospectus supplement to our shelf registration statement that allows us to issue from time to time shares of our common stock up to an aggregate gross amount of $75

Table of Contents

million (the "2017 ATM"). Sales of our common stock, if any, under the 2017 ATM will be made by any method permitted by law deemed to be an "at the market" offering as defined under the Securities Act, including, without limitation, sales made directly on the New York Stock Exchange, on any other existing trading market for our shares of common stock or to or through a market maker or as otherwise agreed by the Company and the sales agent. As of September 30, 2017, we had not issued any shares of our common stock under the 2017 ATM.

On February 6, 2017, the Company completed an underwritten public offering of 10,000,000 shares of the Company's common stock at a price to the public of $12.50 per share ($11.7902 per share, net of underwriting discounts). The Company granted the underwriters a 30-day option to purchase up to an additional 1,500,000 shares of the Company's common stock on the same terms, which was exercised in full and closed on February 6, 2017. The Company received net proceeds of approximately $135.9 million (after deducting underwriting discounts of approximately $7.8 million) from the sale of the shares of common stock. The Company used the net proceeds of the offering for general corporate purposes, including working capital.

Series A Preferred Stock Offering—On September 17, 2012, the Company completed a private placement of 3,000,000 shares of Series A Preferred Stock, which were sold to a group of qualified institutional buyers pursuant to the Rule 144A exemption from registration under the Securities Act. The issue price of each share of the Series A Preferred Stock was $50.00. The Company received net proceeds from the private placement of $144.5 million, after deducting initial purchasers' discounts and commissions and offering costs of $5.5 million.

Each share of Series A Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.325 shares of common stock per share of Series A Preferred Stock (which is equal to an initial conversion price of $21.51 per share of common stock) and is subject to specified adjustments. As of September 30, 2017, based on the initial conversion price, approximately 4,275,640 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Series A Preferred Stock.

The annual dividend on each share of Series A Preferred Stock is 4.875% on the liquidation preference of $50.00 per share and is payable quarterly, in arrears, on each January 1, April 1, July 1 and October 1, when, as and if declared by our Board. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. Dividends are cumulative, and as of September 30, 2017, all dividends accumulated through that date had been paid. The dividends accrued for the period from July 1 to September 30, 2017, were declared by our Board and paid in shares of the Company's common stock on October 2, 2017.

Except as required by law or the Company's Amended and Restated Certificate of Incorporation (the "Charter"), holders of the Series A Preferred Stock will have no voting rights unless dividends fall into arrears for six or more quarterly periods (whether or not consecutive). In that event and until such arrearage is paid in full, the holders of the Series A Preferred Stock and the holders of the Series B Preferred Stock, voting as a single class, will be entitled to elect two directors and the number of directors on our Board will increase by that same number.

At any time on or after October 5, 2017, the Company may at its option cause all outstanding shares of the Series A Preferred Stock to be automatically converted into common stock at the conversion price, if, among other conditions, the closing sale price (as defined) of the Company's common stock equals or exceeds 130% of the conversion price for a specified period prior to the conversion.

If a holder elects to convert shares of Series A Preferred Stock upon the occurrence of certain specified fundamental changes, the Company will be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option time value of the shares of Series A Preferred Stock as a result of the fundamental change.

Series B Preferred Stock Offering—On March 26, 2013, the Company completed a private placement of 4,500,000 shares of Series B Preferred Stock. The issue price of each share of the Series B Preferred Stock was $50.00. The Company received net proceeds from the private placement of $216.6 million, after deducting placement agent's fees and offering costs of $8.4 million. The Company used the net proceeds from this offering to fund a portion of the purchase price for the acquisition of certain assets in Dimmit, Frio, LaSalle, and Zavala Counties, Texas in the Eagle Ford Shale.

Table of Contents

Each share of Series B Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.337 shares of common stock per share of Series B Preferred Stock (which is equal to an initial conversion price of $21.40 per share of common stock) and is subject to specified adjustments. As of September 30, 2017, based on the initial conversion price, approximately 8,244,539 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Series B Preferred Stock.

The annual dividend on each share of Series B Preferred Stock is 6.500% on the liquidation preference of $50.00 per share and is payable quarterly, in arrears, on each January 1, April 1, July 1 and October 1, when, as and if declared by our Board. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. Dividends are cumulative, and as of September 30, 2017, all dividends accumulated through that date had been paid. The dividends accrued for the period from July 1 to September 30, 2017, were declared by our Board and paid in shares of the Company's common stock on October 2, 2017.

Except as required by law or the Charter, holders of the Series B Preferred Stock will have no voting rights unless dividends fall into arrears for six or more quarterly periods (whether or not consecutive). In that event and until such arrearage is paid in full, the holders of the Series B Preferred Stock and the holders of the Series A Preferred Stock, voting as a single class, will be entitled to elect two directors and the number of directors on our Board will increase by that same number.

At any time on or after April 6, 2018, the Company may at its option cause all outstanding shares of the Series B Preferred Stock to be automatically converted into common stock at the conversion price, if, among other conditions, the closing sale price (as defined) of the Company's common stock equals or exceeds 130% of the conversion price for a specified period prior to the conversion.

If a holder elects to convert shares of Series B Preferred Stock upon the occurrence of certain specified fundamental changes, the Company will be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option time value of the shares of Series B Preferred Stock as a result of the fundamental change.

NOL Rights Plan—On July 28, 2015, the Company entered into a net operating loss carryforwards rights plan (as amended, the "Rights Plan") with Continental Stock Transfer & Trust Company, as rights agent. In connection therewith, our Board declared a dividend of one preferred share purchase right ("Right") for each outstanding share of the Company's common stock. The dividend was paid on August 10, 2015 to stockholders of record as of the close of business on August 7, 2015 (the "NOL Record Date"). In addition, one Right automatically attached to each share of common stock issued between the NOL Record Date and such date as when the Rights become exercisable. On March 1, 2017, the Company amended the Rights Plan to, among other things, amend certain defined terms to account for the issuance of warrants and grant of shares of Common Stock to the GSO Funds and the issuance of warrants to the Blackstone Warrantholders in connection with the closing of the Comanche Acquisition.

Common Stock and Stock Warrants Issuance—At the closing of the Comanche Acquisition pursuant to the Amended and Restated Securities Purchase Agreement (the "SPA"), and subject to the other terms and conditions provided therein, (i) the GSO Funds received 1,455,000 shares of the Company's common stock and warrants to purchase 1,940,000 shares of the Company's common stock at an exercise price of $10 per share, subject to customary anti-dilution adjustments; and (ii) Intrepid received 45,000 shares of the Company's common stock and warrants to purchase 60,000 shares of the Company's common stock at an exercise price of $10 per share, subject to customary anti-dilution adjustments. The warrants issued to the GSO Funds and Intrepid expire on March 1, 2032, in each case in accordance with the terms and conditions of the applicable warrant agreement.

Also at the closing of the Comanche Acquisition, the Company entered into (i) three separate warrant agreements to purchase an aggregate of 6,500,000 shares of the Company's common stock with each of Gavilan Resources Holdings—A, LLC, Gavilan Resources Holdings —B, LLC, and Gavilan Resources Holdings—C, LLC (collectively, the "Blackstone Warrantholders"), that provide for a $10 exercise price per share to purchase the Company's common stock, subject to customary anti-dilution adjustments. The warrants issued to the Blackstone Warrantholders expire on March 1, 2022 in accordance with the terms and conditions of the applicable warrant agreement.

Table of Contents

The exercise price and the number of shares of the Company's common stock for which a warrant is exercisable are subject to adjustment from time to time upon the occurrence of certain events including: (i) payment of a dividend or distribution to holders of shares of the Company's common stock payable in the Company's common stock, (ii) a subdivision, combination, or reclassification of the Company's common stock, (iii) the distribution of any rights, options or warrants (excluding rights issued under the Rights Plan) to all holders of the Company's common stock entitling them for a certain period of time to purchase shares of the Company's common stock at a price per share less than the fair market value per share, and (iv) payment of a cash distribution to all holders of the Company's common stock or a distribution to all holders of the Company's common stock any shares of the Company's capital stock, evidences of indebtedness, or any of assets or any rights, warrants or other securities of the Company. The warrant agreements also provide that, if the Company proposes a voluntary or involuntary dissolution, liquidation or winding up of the affairs of the Company, the holders of the warrants will receive the kind and number of other securities or assets which the holder would have been entitled to receive if the holder had exercised the warrant in full immediately prior to the time of such dissolution, liquidation or winding up and the right to exercise the warrant will terminate on the date on which the holders of record of the shares of common stock are entitled to exchange their shares for securities or assets deliverable upon such dissolution, liquidation or winding up.

In addition, the Company entered into separate registration rights agreements with the Blackstone Warrantholders, the GSO Funds, and Intrepid (collectively, the "Registration Rights Agreements"). The Registration Rights Agreements grant the parties certain registration rights for the shares of our common stock acquired by the parties, including the shares issuable upon the exercise of the warrants to purchase the Company's common stock. The Registration Rights Agreements with the Blackstone Warrantholders and the GSO Funds provide that the Company will use its reasonable best efforts to prepare and file a shelf registration statement with the SEC to permit the public resale of all registrable securities covered by the applicable Registration Rights Agreement within 18 months of the date of the agreement and to cause such shelf registration statement to be declared effective no later than two years after the date of the agreement.

The Registration Rights Agreements include piggyback rights for the applicable holders, which provide that, if the Company proposes to file certain registration statements or supplements to certain effective registration statements for the sale of shares of the Company's common stock in an underwritten offering for its own account or that of another person or both, then the Company is required to offer the holders the opportunity to include in such underwritten offering such number of registrable securities as each such holder may request, subject to certain cutback rights if the Company has been advised by the managing underwriter that the inclusion of registrable securities for sale for the benefit of the holders will have an adverse effect on the price, timing or distribution of the shares of common stock in the underwritten offering.

SN UnSub Preferred Unit Issuance—At the closing of the Comanche Acquisition, pursuant to the SPA and subject to the other terms and conditions provided therein, the GSO Funds purchased 485,000 SN UnSub Preferred Units for $485,000,000 and Intrepid purchased 15,000 SN UnSub Preferred Units for $15,000,000. The applicable parties entered into an amended and restated partnership agreement of SN UnSub (the "Partnership Agreement") and an amended and restated limited liability company agreement of SN UnSub General Partner (the "GP LLC Agreement").

Under the terms of the Partnership Agreement, holders of the SN UnSub Preferred Units are entitled to receive distributions of 10.0% per annum, payable quarterly in cash, unless a cash payment is then prohibited by certain of SN UnSub's debt agreements, in which case such distribution will be deemed to have been paid in kind. SN UnSub may not make distributions on the SN UnSub common units until the preferred units are redeemed in full.

The SN UnSub Preferred Units have priority over the common units, to the extent of the Base Return (as defined below), upon a liquidation, sale of all or substantially all assets, certain change of control and exit transactions.

Table of Contents

SN UnSub may, from time to time and subject to the conditions set forth in the Partnership Agreement and the SN UnSub Credit Agreement, redeem SN UnSub Preferred Units at a purchase price per unit sufficient to provide the holders of the SN UnSub Preferred Units the greater of (i) a 14.0% internal rate of return for such unit and (ii) 1.50x the purchase price for such unit, in each case inclusive of previous distributions made in cash (the “Base Return”). Partners holding a majority of the SN UnSub Preferred Units will have the option to request SN UnSub to redeem all of the preferred units for the Base Return at any time following the seventh anniversary of issuance or upon the occurrence of certain change of control transactions, as further described in the Partnership Agreement.

If (i) the SN UnSub Preferred Units are not timely redeemed by SN UnSub when required, (ii) SN UnSub fails, after March 1, 2018, to pay the holders of the SN UnSub Preferred Units a cash distribution in any two quarters, regardless of whether consecutive, and such failure is continuing, (iii) SN UnSub takes certain material actions without the consent of the holders of the SN UnSub Preferred Units, when required, (iv) certain events of default under SN UnSub and the Company’s credit agreements have occurred or (v) SN Maverick is removed as operator under the JDA under certain circumstances, then a controlled affiliate of GSO will be entitled to appoint a majority of the members of the board of directors of SN UnSub General Partner and may cause a sale of the assets or equity of SN UnSub in order to redeem the SN UnSub Preferred Units.

The SN UnSub Preferred Units issued in March 2017 are accounted for as mezzanine equity in the consolidated balance sheet consisting of the following as of September 30, 2017 (in thousands):

	September 30, 2017
Mezzanine equity beginning balance	$ —
Private placement of SN UnSub Preferred Units	500,000
Discount	(97,807)
Accretion of discount	12,509
Dividends accrued (1)	29,167
Dividends paid (2)	(29,167)
Total mezzanine equity	$ 414,702

(1) In accordance with the Partnership Agreement and SN UnSub Credit Agreement, cash distributions for the 10% dividend on the SN UnSub Preferred Units are prohibited through February 28, 2018, and thus, the dividends for the periods presented are deemed to have been paid in kind and accrued.

(2) Dividends paid in 2017 represent tax distributions from available cash to holders of the SN UnSub Preferred Units. The Partnership Agreement provides that tax distributions shall be treated as advances of any amounts holders of the SN UnSub Preferred Units are entitled to receive, and shall be offset against any amounts holders of SN UnSub Preferred Units are entitled to receive.

34

Table of Contents

Earnings (Loss) Per Share—The following table shows the computation of basic and diluted net income (loss) per share for the three and nine months ended September 30, 2017 and 2016 (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income (loss)	$ (44,782)	$ (66,262)	$ 11,229	$ (314,906)
Less:				
Preferred stock dividends	(3,988)	(3,987)	(11,962)	(11,961)
Preferred unit dividends and distributions	(8,347)	—	(35,762)	—
Preferred unit amortization	(5,517)	—	(12,509)	—
Net income allocable to participating securities(1)(2)	—	—	—	—
Net loss attributable to common stockholders	$ (62,634)	$ (70,249)	$ (49,004)	$ (326,867)
Weighted average number of unrestricted outstanding common shares used to calculate basic net loss per share	77,453	59,190	74,531	58,782
Dilutive shares(3)(4)(5)	—	—	—	—
Denominator for diluted income (loss) per common share	77,453	59,190	74,531	58,782
Net loss per common share - basic	$ (0.81)	$ (1.19)	$ (0.66)	$ (5.56)
Net loss per common share - diluted	$ (0.81)	$ (1.19)	$ (0.66)	$ (5.56)

(1) The Company’s restricted shares of common stock are participating securities.

(2) For the three and nine months ended September 30, 2016, no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company’s losses.

(3) The three and nine months ended September 30, 2017 excludes 694,739 and 1,101,020 shares, respectively, of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed conversion of the 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.

(4) The three and nine months ended September 30, 2016 excludes 1,035,102 and 1,565,007 shares, respectively, of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed conversion of the 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.

(5) The three and nine months ended September 30, 2017 excludes 8,500,000 shares of common stock from exercisable warrants from the calculation of the denominator for diluted earnings per common share as the exercise price is greater than the average market prices of the Company’s common stock for the periods and the effect would be anti-dilutive to the computation.

Note 14. Stock Based Compensation

At the Annual Meeting of Stockholders of the Company held on May 24, 2016 ("2016 Annual Meeting"), the Company's stockholders approved the Sanchez Energy Corporation Third Amended and Restated 2011 Long Term Incentive Plan (the "LTIP"). Our Board had previously approved the LTIP on May 21, 2016, subject to stockholder approval.

The Company's directors and consultants as well as employees of the Sanchez Group who provide services to the Company are eligible to participate in the LTIP. Awards to participants may be made in the form of stock options, stock appreciation rights, restricted shares, phantom stock, other stock-based awards or stock awards, or any combination thereof. The maximum shares of common stock that may be delivered with respect to awards under the LTIP shall be (i) 17,239,790 shares plus (ii) upon the issuance of additional shares of common stock from time to time after April 1, 2016, 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 or Compensation Committee; provided, however, shares withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP. If any award is forfeited, cancelled, exercised, paid, or otherwise terminates or expires without the

Table of Contents

actual delivery of shares of common stock pursuant to such award (the grant of restricted stock is not a delivery of shares of common stock for this purpose), the shares of common stock subject to such award shall again be available for awards under the LTIP. There shall not be any limitation on the number of awards that may be paid in cash. Any shares delivered pursuant to an award shall consist, in whole or in part, of shares of common stock newly issued by the Company, shares of common stock acquired in the open market, from any affiliate of the Company, or any combination of the foregoing, as determined by our Board or Compensation Committee in its discretion.

The LTIP is administered by the Compensation Committee of the Board as appointed by our Board. Our Board may terminate or amend the LTIP at any time with respect to any shares for which a grant has not yet been made. Our Board has the right to alter or amend the LTIP or any part of the LTIP from time to time, including increasing the number of shares that may be granted, subject to stockholder approval as may be required by the exchange upon which the shares of common stock are listed at that time, if any. No change may be made in any outstanding grant that would materially reduce the benefits of the participant without the consent of the participant. The LTIP will expire upon its termination by our Board or, if earlier, when no shares remain available under the LTIP for awards. Upon termination of the LTIP, awards then outstanding will continue pursuant to the terms of their grants.

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

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

During the three and nine months ended September 30, 2017, the Company issued approximately 0.1 million and 2.1 million shares, respectively, of restricted common stock pursuant to the LTIP to certain employees (including the Company’s officers) and consultants of SOG, with whom the Company has a services agreement. The majority of these shares of restricted common stock vest in equal annual amounts over a three-year period.

In February 2016 and April 2016, the Compensation Committee approved several new forms of agreement for use in equity awards pursuant to the LTIP. The new forms of agreements consist of two new forms of restricted stock award agreements, one of which provides for vesting in equal annual increments over a three year period from the grant date (the "Grant Date") and the other of which provides for cliff vesting five years after the Grant Date or earlier if the common stock closing price equals or exceeds certain benchmarks as set forth in the form of agreement (the "Performance Accelerated Restricted Stock" or "PARS"), and two new forms of phantom stock agreements payable only in cash, one of which provides for vesting in equal annual increments over a three year period from the Grant Date (the "Phantom Stock") and the other of which provides for cliff vesting five years after the Grant Date or earlier if the Company's common stock closing price equals or exceeds certain benchmarks as set forth in the form of agreement (the "Performance Accelerated Phantom Stock" or "PAPS").

The PARS, PAPS and Phantom Stock awards granted to certain employees of the Sanchez Group (including those employees of the Sanchez Group who also serve as the Company's officers) and consultants in exchange for services are considered awards to non-employees and the Company records stock-based compensation expense for these awards at fair value in accordance with the provisions of ASC 718, "Compensation – Stock Compensation." In accordance with the guidance, the inclusion of market performance acceleration conditions on the PARS does not change the accounting classification as compared to the restricted stock without market performance acceleration conditions, as both are still classified as equity within the Company's balance sheet. The Phantom Stock awards are

Table of Contents

required to be settled in cash by the Company and, per the guidance, should be classified as a liability. Compensation expense for the unvested awards is revalued at each period end and is amortized over the vesting period of the stock-based award using the straight-line method.

During the three and nine months ended September 30, 2017, the Company issued approximately 0.1 million and 2.1 million shares of Phantom Stock, respectively, pursuant to the LTIP to certain employees of SOG (including the Company's officers), with whom the Company has a services agreement. The majority of these shares of Phantom Stock vest in equal annual amounts over a three-year period.

On March 1, 2017, the Company's Chief Executive Officer, Executive Chairman of the Board, President, and Chief Operating Officer entered into a new form of agreement for use in equity awards pursuant to the LTIP, for 245,234 target shares of the Company's common stock, 245,234 target shares of the Company's common stock, 245,234 target shares of the Company's common stock, and 81,745 target shares of the Company's common stock, respectively. The new form of agreement is a performance phantom stock agreement payable in shares of common stock (the "Performance Phantom Stock Agreement"). The phantom shares granted pursuant to the Performance Phantom Stock Agreement (the "Performance Awards") will vest (if any) in equal annual increments over a five-year period ranging from 0% to 200% of the target phantom shares granted based on the Company's share price appreciation relative to the share price appreciation of the S&P Oil & Gas Exploration & Production Select Industry Index for each year in the five-year performance period beginning on January 1, 2017 and ending on December 31, 2021, subject each officer's continuous service with the Company through each vesting date.

The Performance Awards are considered awards to non-employees and the Company records stock-based compensation expense for these awards at fair value in accordance with the provisions of ASC 718, "Compensation – Stock Compensation." In accordance with the guidance, the Performance Awards are classified as equity within the Company's balance sheet, as they are settled in shares of the Company's common stock. The Performance Awards have graded-vesting features and as such, the compensation expense for the unvested awards is calculated using the graded-vesting method whereby the Company recognizes compensation expense over the requisite service period for each separately vesting tranche of the award as though they were, in substance, multiple awards. In addition, the estimated value of each tranche will be revalued at each period end and amortized over the vesting period.

The Company recognized the following stock-based compensation expense (in thousands) which is included in general and administrative expense in the condensed consolidated statements of operations, for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Restricted stock awards, directors	$ 346	$ 2,344	$ 4,947	$ 4,622

Restricted stock awards, non-employees	1,071	5,966	11,619	13,283
Performance awards	(506)	—	771	—
Phantom stock awards	(209)	4,492	13,756	8,120
Total stock-based compensation expense	$ 702	$ 12,802	$ 31,093	$ 26,025

Based on the $4.82 per share closing price of the Company's common stock on September 30, 2017, there was approximately $23.6 million of unrecognized compensation cost related to the non vested restricted shares outstanding. The cost is expected to be recognized over an average period of approximately 2.19 years.

Based on the $4.82 per share closing price of the Company's common stock on September 30, 2017, there was approximately $0.6 million of unrecognized compensation cost related to the non vested PARS restricted shares outstanding. The cost is expected to be recognized over an average period of approximately 3.54 years.

Based on the $4.82 per share closing price of the Company's common stock on September 30, 2017, there was approximately $13.5 million of unrecognized compensation cost related to the non vested PAPS and Phantom Stock award shares outstanding. The cost is expected to be recognized over an average period of approximately 2.79 years.

Table of Contents

Based on the estimated per share price of the Performance Awards on September 30, 2017, there was approximately $3.0 million of unrecognized compensation cost related to the Performance Awards. The cost is estimated to be recognized over a weighted average period of approximately 3.03 years.

A summary of the status of the non-vested shares for the three and nine months ended September 30, 2017 and 2016 is presented below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Non-vested common stock, beginning of period	6,059	7,961	7,967	4,426
Granted	61	67	2,136	5,405
Vested	(260)	(158)	(4,196)	(1,588)
Forfeited	(20)	(86)	(67)	(459)
Non-vested common stock, end of period	5,840	7,784	5,840	7,784

As of September 30, 2017, approximately 8.1 million shares remain available for future issuance to participants under the LTIP.

A summary of the status of the non vested Phantom Stock shares and PAPS for the three and nine months ended September 30, 2017 and 2016 is presented below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Non-vested phantom stock, beginning of period	4,198	3,834	4,012	—
Granted	80	55	2,066	3,889
Vested	(188)	—	(1,968)	—
Forfeited	(17)	(75)	(37)	(75)
Non-vested phantom stock, end of period	4,073	3,814	4,073	3,814

Note 15. Income Taxes

The Company used a year-to-date effective tax rate method for recording income taxes for the nine month periods ended September 30, 2017 and 2016. This method is based on our expectations at September 30, 2017 and 2016 that a small change in our estimated ordinary income could result in a large change in the estimated annual effective tax rate. We will use this method each quarter until such time a return to the annualized effective tax rate method is deemed appropriate.

The Company's effective tax rate for the nine months ended September 30, 2017 and 2016 was (12.1)% and (0.5)%, respectively. The Company’s effective tax rate of (12.1)% for the nine months ended September 30, 2017 is primarily related to the recording of certain deferred tax liabilities associated with the Comanche Acquisition that were recorded directly to equity, whereas the correlating movement in the valuation allowance was recorded directly to income tax expense. The difference between the statutory federal income taxes calculated using a maximum U.S. Federal statutory corporate income tax rate of 35% and the Company’s effective tax rate of (0.5)% for the nine months ended September 30, 2016 is primarily related to the valuation allowance on deferred tax assets.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that the deferred tax assets will be realized and, therefore, has established a valuation allowance to reduce the deferred tax assets as of September 30, 2017.

Table of Contents

The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

At September 30, 2017, the Company had no material uncertain tax positions.

Note 16. Commitments and Contingencies

Litigation

From time to time, the Company may be involved in lawsuits that arise in the normal course of its business. We are not aware of any material governmental proceedings against us or contemplated to be brought against us.

On December 4, 2013, and December 16, 2013, three derivative actions were filed in the Court of Chancery of the State of Delaware ("Court of Chancery") against the Company, certain of its officers and directors, Sanchez Resources, Altpoint Capital Partners LLC and Altpoint Sanchez Holdings, LLC (Friedman v. A.R. Sanchez, Jr. et al., No. 9158; City of Roseville Employees' Retirement System v. A.R. Sanchez, Jr. et al., No. 9132; and Delaware County Employees Retirement Fund v. A.R. Sanchez, Jr. et al., No. 9165 (collectively, the ''Consolidated Derivative Actions'')).

On December 20, 2013, the Consolidated Derivative Actions were consolidated, co-lead counsel for the plaintiffs was appointed and the plaintiffs were ordered to file an amended consolidated complaint (In re Sanchez Energy Derivative Litigation, Consolidated C.A. No. 9132-VCG, hereinafter, the "Delaware Derivative Action"). On January 28, 2014, a verified consolidated stockholder derivative complaint was filed. The Consolidated Derivative Actions concern the Company's purchase of working interests in the TMS from SR Acquisition I, LLC ("SR"). Plaintiffs alleged breaches of fiduciary duty against the individual defendants as directors of the Company; breaches of fiduciary duty against Antonio R. Sanchez, III as an executive director of the Company; aiding and abetting breaches of fiduciary duty against SR, Eduardo Sanchez, Altpoint Capital Partners LLC and Altpoint Sanchez Holdings, LLC; and unjust enrichment against A.R. Sanchez, Jr. and Antonio R. Sanchez, III. All of the defendants filed a motion to dismiss on April 1, 2014, which was granted by the Court of Chancery on November 25, 2014. On October 2, 2015, the Delaware Supreme Court reversed the motions to dismiss and remanded the case to the Court of Chancery for further proceedings. The Consolidated Derivative Actions are currently in the late stages of discovery. A mediation in connection with the matter was held on July 7, 2016. A second mediation in connection with the matter was held on June 13, 2017. On August 11, 2017, the Company, the plaintiffs and all named defendants entered into a Stipulation of Settlement (the "Stipulation") reflecting the terms of the settlement of the Delaware Derivative Action. While the defendants continue to deny each of the plaintiffs' claims and expressly deny any fault, wrongdoing or liability, the defendants agreed to the settlement solely to resolve the disputes, to avoid the costs and risks of further litigation and to avoid further distraction to the Company's management. The litigation was settled, subject to the approval of the Court of Chancery and in consideration of, among other things, the following: (i) a payment to the Company (net of fees, expenses and other amounts) of an aggregate of $11.75 million, (ii) the transfer of the equity of Sanchez Resources and certain related royalty interests in any TMS acreage to the Company, and (iii) the removal of Alan Jackson and Greg Colvin from the Company's compensation committee. The terms of the Stipulation are subject to approval by the Court of Chancery. The Stipulation was filed with the Court of Chancery on August 14, 2017, and a hearing on the settlement is set for November 6, 2017 in the Court of Chancery.

On January 9, 2014, a derivative action was filed in 333rd district court in Harris County, Texas against the Company and certain of its officers and directors, styled Martin v. Sanchez, No. 2014-01028 (333rd Dist. Harris County, Texas). The complaint alleged a breach of fiduciary duty, corporate waste and unjust enrichment against various officers and directors. No action has been taken to date and damages are unspecified. On March 14, 2014, this action was stayed following a ruling on the motion to dismiss in the Delaware Derivative Action. After the motions to dismiss were granted in the Delaware Derivative Action, the parties entered into another agreed stay pending the appeal of the Delaware Derivative Action to the Delaware Supreme Court. This stay was entered by the court on February 5, 2015. This action is in its preliminary stages and currently subject to the stay. The Company is currently unable to reasonably predict an outcome or to estimate a range of reasonably possible loss, if any. Defendants believe that the allegations within the Martin action are without merit and intend to vigorously defend themselves against the claims raised.

Table of Contents

Catarina Drilling Obligation

In connection with the Catarina Acquisition, the undeveloped acreage we acquired is subject to a continuous drilling obligation. Such drilling obligation requires us to drill (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120-day period in order to maintain rights to any future undeveloped acreage. Up to 30 wells drilled in excess of the minimum 50 wells in a given annual drilling 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. The lease also creates 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.

Comanche Drilling Obligation

In connection with the Comanche Acquisition, we, through our subsidiaries, SN Maverick and SN UnSub, and Gavilan, entered into a development agreement with Anadarko. The development agreement requires us to drill 60 wells in each annual period commencing on September 1, 2017 and continuing thereafter until September 1, 2022. The development agreement permits up to 30 wells drilled 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. The development agreement contains a parent guarantee of the performance of SN Maverick and SN UnSub. If we fail to complete and equip the required number of wells in a given year (after applying any qualifying additional wells from previous years), we and Gavilan must pay Anadarko E&P Onshore, LLC a default fee of $0.2 million for each well we do not timely complete and equip. 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.

Lease Payment Obligations

As of September 30, 2017, the Company had $220.0 million in lease payment obligations that satisfy operating lease criteria. These obligations include: (i) $127.3 million in payments due with respect to firm commitment of oil and natural gas volumes under the gathering agreement contract signed with SNMP as part of the Western Catarina Midstream Divestiture that commenced on October 14, 2015 and continues until October 13, 2020, (ii) $82.4 million for corporate and field office leases with expiration dates through March 2025, (iii) $5.3 million for a ground lease agreement for land owned by the Calhoun Port Authority that commenced during the third quarter of 2014 and expires in August 2024, and (iv) $5.0 million for a 10 year acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas.

The lease agreement for the acreage in Kenedy County, Texas includes a contractual requirement for the Company to spend a minimum of $4 million to make permanent improvements over the ten year life of the lease. The lease agreement does not specify the timing for such improvements to be made within the lease term. The Company has the right to terminate the lease obligation without penalty at any time with nine months advanced written notice and payment of any accrued leasehold expenses.

Volume Commitments

As is common in our industry, the Company is party to certain oil and natural gas gathering and transportation and natural gas processing agreements that obligate us to deliver a specified volume of production over a defined time horizon. If not fulfilled, the Company is subject to deficiency payments. In particular, with respect to the Comanche Assets, on June 1, 2017, the Company entered into several agreements that require the delivery of variable minimum monthly quantities (See Note 3, "Acquisitions and Divestitures—Comanche Acquisition"). As of September 30, 2017, the Company had approximately $839.3 million in future commitments related to oil and natural gas gathering and transportation agreements ($20.9 million for the three months ended December 31, 2017, $270.9 million for 2018 through 2020, $254.6 million from 2021 through 2023, and $293.0 million under commitments expiring after December 31, 2023, in the aggregate) and approximately $65.3 million in future commitments related to natural gas processing agreements ($4.4 million for the three months ended December 31, 2017, $43.2 million for 2018 through 2020, $17.7 million from 2021 through 2023, and no commitments expiring after December 31, 2023) that are not recorded in the accompanying unaudited consolidated balance sheets.

From inception of these contracts through September 30, 2017, the Company incurred expenses related to

Table of Contents

deficiency fees of approximately $2.4 million that are reported on the unaudited consolidated statements of operations in the "Oil and natural gas production expenses" line item. We do not anticipate that any future deficiency payments under these contracts would be material, and expect to fulfill these obligations in the future based on our anticipated development plan for the Comanche Assets.

Note 17. Subsidiary Guarantors

The Company filed registration statements on Form S-3 with the SEC, which became effective January 14, 2013, June 11, 2014 and April 25, 2016 and registered, among other securities, debt securities. The subsidiaries of the Company named therein are co-registrants with the Company, and the registration statement registered guarantees of debt securities by such subsidiaries. As of September 30, 2017, such subsidiaries are 100 percent owned by the Company and any guarantees by these subsidiaries will be full and unconditional (except for customary release provisions). In the event that more than one of these subsidiaries provide guarantees of any debt securities issued by the Company, such guarantees will constitute joint and several obligations.

The Company also filed a registration statement on Form S-4 with the SEC, which became effective on June 20, 2014, pursuant to which the Company completed an offering of the 7.75% Notes, which are guaranteed by its subsidiaries named therein. As of September 30, 2017, such guarantor subsidiaries were 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several. The Company also filed a registration statement on Form S-4 with the SEC, which became effective on January 23, 2015, pursuant to which the Company completed an offering of the 6.125% Notes, which are guaranteed by its subsidiaries named therein. As of September 30, 2017, such guarantor subsidiaries are 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several.

The Company’s 7.75% Notes and 6.125% Notes are guaranteed by all of the Company’s subsidiaries, except for SN UR Holdings, LLC, SN Services, LLC, SNT, SN Midstream, Manager, SN UnSub General Partner, SN UnSub Holdings, SN UnSub and SN Capital, LLC, which are unrestricted subsidiaries of the Company.

The rules of Regulation S-X Rule 3-10 require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. See Note 18, “Condensed Consolidating Financial Information” for further discussion regarding the condensed consolidating financial information for guarantor and non-guarantor subsidiaries.

The Company has no assets or operations independent of its subsidiaries and there are no significant restrictions upon the ability of its subsidiaries to distribute funds to the Company, except as noted below. SN UnSub's and SN UnSub General Partner's ability to distribute funds to the Company or its subsidiaries by dividend or loan is restricted by (i) the restrictive or negative covenants in the SN UnSub Credit Agreement and (ii) the terms of the SN UnSub Preferred Units and the consent or approval rights of the GSO Funds (or their representatives or affiliates) under the Partnership Agreement and the GP LLC Agreement, as the case may be (see Note 6, "Long-Term Debt—SN UnSub Credit Agreement" and Note 13, "Stockholders' and Mezzanine Equity—SN UnSub Preferred Units Issuance").

Not

Note 18. Condensed Consolidating Financial Information

As noted above, the rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis (in thousands) and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had such guarantor subsidiaries operated as independent entities.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are, therefore, reflected in the parent company's investment accounts and earnings. The principal elimination entries set forth below eliminate investments in

Table of Contents

subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity.

A summary of the condensed consolidated guarantor balance sheets for the periods ended September 30, 2017 and December 31, 2016 is presented below (in thousands):

	September 30, 2017				
Assets	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 367,081	$ 154,267	$ 106,392	$ (311,982)	$ 315,758
Total oil and natural gas properties, net	3,742	1,110,912	729,081	-	1,843,735
Investment in subsidiaries	1,020,359	-	-	(1,020,359)	-
Other assets	23,317	5,907	51,382	-	80,606
Total Assets	$ 1,414,499	$ 1,271,086	$ 886,855	$ (1,332,341)	$ 2,240,099
Liabilities and Shareholders' Equity					
Current liabilities	$ 114,823	$ 358,049	$ 198,065	$ (311,981)	$ 358,956
Long-term liabilities	1,756,534	24,779	190,257	-	1,971,570
Mezzanine equity	-	-	414,702	-	414,702
Total shareholders' equity (deficit)	(456,858)	888,258	83,831	(1,020,360)	(505,129)
Total Liabilities and Shareholders' Equity (Deficit)	$ 1,414,499	$ 1,271,086	$ 886,855	$ (1,332,341)	$ 2,240,099

	December 31, 2016				
Assets	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 428,384	$ 157,154	$ 158,589	$ (181,322)	$ 562,805
Total oil and natural gas properties, net	-	658,588	-	-	658,588
Investment in subsidiaries	734,704	-	-	(734,704)	-
Other assets	14,376	15,221	35,290	-	64,887
Total Assets	$ 1,177,464	$ 830,963	$ 193,879	$ (916,026)	$ 1,286,280
Liabilities and Shareholders' Equity					
Current liabilities	$ 109,539	$ 78,344	$ 170,435	$ (181,321)	$ 176,997
Long-term liabilities	1,764,064	25,087	16,273	(1)	1,805,423
Total shareholders' equity (deficit)	(696,139)	727,532	7,171	(734,704)	(696,140)
	$ 1,177,464	$ 830,963	$ 193,879	$ (916,026)	$ 1,286,280

Total Liabilities and Shareholders'
Equity (Deficit)

A summary of the condensed consolidated guarantor statements of operations for the three and nine months

Table of Contents

ended September 30, 2017 and September 30, 2016 is presented below (in thousands):

	Three Months Ended September 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 118,616	$ 66,190	$ -	$ 184,806
Total operating costs and expenses	(19,420)	113,368	56,023	(45)	149,926
Other income (expense)	(56,015)	(4,776)	(18,826)	(45)	(79,662)
Income (loss) before income taxes	(36,595)	472	(8,659)	-	(44,782)
Income tax benefit	-	-	-	-	-
Equity in income (loss) of subsidiaries	(8,187)	-	-	8,187	-
Net income (loss)	$ (44,782)	$ 472	$ (8,659)	$ 8,187	$ (44,782)

	Nine Months Ended September 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 341,747	$ 152,606	$ -	$ 494,353
Total operating costs and expenses	67,307	256,726	128,069	(545)	451,557
Other income (expense)	(59,393)	7,526	19,637	(545)	(32,775)
Income (loss) before income taxes	(126,700)	92,547	44,174	-	10,021
Income tax benefit	1,208	-	-	-	1,208
Equity in loss of subsidiaries	136,721	-	-	(136,721)	-
Net income (loss)	$ 11,229	$ 92,547	$ 44,174	$ (136,721)	$ 11,229

	Three Months Ended September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 114,807	$ -	$ -	$ 114,807
Total operating costs and expenses	27,191	139,426	470	-	167,087
Other income (expense)	(11,051)	(1,556)	66	-	(12,541)
Loss before income taxes	(38,242)	(26,175)	(404)	-	(64,821)
Income tax expense	(1,441)	-	-	-	(1,441)

Equity in income (loss) of subsidiaries	(26,581)	-	-	26,581	-
Net loss	$ (66,264)	$ (26,175)	$ (404)	$ 26,581	$ (66,262)

Table of Contents

	Nine Months Ended September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 305,591	$ -	$ -	$ 305,591
Total operating costs and expenses	70,982	437,603	1,480	-	510,065
Other income (expense)	(110,078)	(1,331)	2,418	-	(108,991)
Income (loss) before income taxes	(181,060)	(133,343)	938	-	(313,465)
Income tax expense	(1,441)	-	-	-	(1,441)
Equity in income (loss) of subsidiaries	(132,406)	-	-	132,406	-
Net income (loss)	$ (314,907)	$ (133,343)	$ 938	$ 132,406	$ (314,906)

A summary of the condensed consolidated guarantor statements of cash flows for the nine months ended September 30, 2017 and September 30, 2016 is presented below (in thousands):

	Nine Months Ended September 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (144,240)	$ 248,264	$ 66,710	$ -	$ 170,734
Net cash used in investing activities	(214,501)	(455,620)	(766,750)	205,491	(1,231,380)
Net cash provided by financing activities	108,629	223,401	606,418	(205,491)	732,957
Net increase (decrease) in cash and cash equivalents	(250,112)	16,045	(93,622)	-	(327,689)
Cash and cash equivalents, beginning of period	343,941	-	157,976	-	501,917
Cash and cash equivalents, end of period	$ 93,829	$ 16,045	$ 64,354	$ -	$ 174,228

	Nine Months Ended September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	$ (11,203)	$ 149,765	$ (450)	$ -	$ 138,112

Net cash provided by (used in) operating activities					
Net cash provided by (used in) investing activities	(323,583)	(241,349)	8,322	319,620	(236,990)
Net cash provided by (used in) financing activities	(7,641)	91,584	228,036	(319,620)	(7,641)
Net increase (decrease) in cash and cash equivalents	(342,427)	-	235,908	-	(106,519)
Cash and cash equivalents, beginning of period	434,933	-	115	-	435,048
Cash and cash equivalents, end of period	$ 92,506	$ -	$ 236,023	$ -	$ 328,529

Note 19. Variable Interest Entities

During the first quarter 2016, the Company adopted ASU 2015-02, "Consolidation—Amendments to the Consolidation Analysis," which introduces a separate analysis for determining if limited partnerships and similar entities are variable interest entities ("VIEs") and clarifies the steps a reporting entity would have to take to determine whether the voting rights of stockholders in a corporation or similar entity are substantive.

As noted above in Note 8, "Investments," the Company, via SN Catarina, purchased from a subsidiary of Targa a 10% undivided interest in the SOII Facility in 2015. The Company determined that ownership in the SOII Facility is more similar to limited partnerships than corporations. Under the revised guidance of ASU 2015-02, a limited

Table of Contents

partnership or similar entity with equity at risk will not be a VIE if they are able to exercise kick-out rights over the general partner(s) or they are able to exercise substantive participating rights. On June 14, 2017, SN Catarina completed the SOII Disposition for $12.5 million in cash. Prior to the SOII Disposition, we concluded that the investment in SOII Facility is a VIE under the revised guidance because we could not remove Targa as operator and we did not have substantive participating rights. In addition, Targa had the discretion to direct activities of the VIE regarding the risks associated with price, operations, and capital investment which have the most significant impact on the VIE economic performance.

As noted above in Note 8, "Investments," in November 2016, the Company purchased common units of SNMP for $25.0 million as part of a private equity issuance. Rather than accounting for the investment under the equity method, the Company elected the fair value option to account for its interest in SNMP. The Company's investment in SNMP represents a VIE that could expose the Company to losses limited to the equity in the investment at any point in time. The carrying amounts of the investment in SNMP and the Company's maximum exposure to loss as of September 30, 2017, was approximately $25.6 million.

Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Company's maximum exposure to loss as of September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Beginning Balance	$ 39,656	$ 37,527
Earnings on (distributions from) equity investments	(311)	311
Gain (Loss) from change in fair value of investment in SNMP	(1,250)	1,818
Sale of investments	(12,527)	—
Equity in equity investments	$ 25,568	$ 39,656

	September 30, 2017	December 31, 2016
Equity in equity investments	$ 25,568	$ 39,656
Guarantees of capital investments	—	—
Maximum exposure to loss	$ 25,568	$ 39,656

Note 20. Subsequent Events

On October 2, 2017, dividends declared by our Board and accrued for the period from July 1 to September 30, 2017 for the Series A Preferred Stock and Series B Preferred Stock were paid in shares of the Company's common stock.

Table of Contents

Item 2. 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 condensed consolidated financial statements and related notes appearing in Part I, Item 1 of this Quarterly Report on Form 10 Q and information contained in our 2016 Annual Report. The following discussion contains "forward looking statements" that reflect our future plans, estimates, beliefs and expected performance. Please see "Cautionary Note Regarding Forward Looking Statements."

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 U.S. onshore unconventional oil and natural gas resources, with a current focus on the horizontal development of significant resource potential from the Eagle Ford Shale in South Texas. We also hold an undeveloped acreage position in the TMS in Mississippi and Louisiana, which offers future upside opportunity. As of September 30, 2017, we have assembled over 286,000 net leasehold acres representing an approximate 59% average working interest in the Eagle Ford Shale. For the year 2017, we plan to invest substantially all of our capital budget in the Eagle Ford Shale. We continue to evaluate opportunities to grow both our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on both the opportunities and the financing alternatives available to us at the time we consider such opportunities.

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

Transaction	Transaction Date	Transaction Effective Date	Core Area	Net Acreage Acquired	Net Acreage Remaining at 6/30/16	Approximate Disposition (Purchase) Price (millions)
Javelina Disposition	9/19/2017	8/1/2017	Eagle Ford	N/A	N/A	$ 105
Marquis Disposition	6/15/2017	1/1/2017	Eagle Ford	N/A	N/A	$ 50
Comanche Acquisition	3/1/2017	7/1/2016	Eagle Ford, Pearsall	155,000	155,000	$ (1,039)

Cotulla Disposition	12/14/2016	6/1/2016	Cotulla, Eagle Ford	N/A	N/A	$ 167
Carnero Processing Disposition	11/22/2016	11/22/2016	N/A	N/A	N/A	$ 56
Production Asset Transaction	11/22/2016	7/1/2016	Palmetto and Cotulla, Eagle Ford	N/A	N/A	$ 26
Carnero Gathering Disposition	7/5/2016	7/5/2016	N/A	N/A	N/A	$ 37

On September 19, 2017, the Company completed the Javelina Disposition for approximately $105 million in cash. Consideration received from the Javelina Disposition was based on an August 1, 2017 effective date and is subject to normal and customary post-closing adjustments.

On June 15, 2017, the Company completed the Marquis Disposition for approximately $44.0 million in cash and Lonestar Series B Convertible Preferred Stock structured to be converted into 1.5 million shares of Lonestar Class A Common Stock upon the satisfaction of certain conditions. The value of the Lonestar Series B Convertible Preferred Stock on the closing date was approximately $6.0 million. Consideration received from the Marquis Disposition was based on a January 1, 2017 effective date and is subject to other normal and customary post-closing adjustments.

On March 1, 2017, the Company completed the Comanche Acquisition for approximately $2.1 billion in cash (approximately $1.0 billion, net to the Company), after preliminary closing adjustments. The Comanche Assets are primarily located in the Western Eagle Ford and have significantly expanded our asset base and production. The Comanche Assets consist 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, with an approximate 49% average working interest therein. The Company acquired half of the 49% working interest in the Comanche Assets. The effective date of the transaction is July 1, 2016.

Table of Contents

On December 14, 2016, SN Cotulla completed the initial closing of the Cotulla Disposition for aggregate consideration of approximately $167.4 million after normal and customary post-closing adjustments. Consideration received from the Cotulla Disposition was based on a June 1, 2016 effective date.

On November 22, 2016, SN Midstream completed the Carnero Processing Disposition to SNMP, a joint venture that is 50% owned by Targa for an initial payment of approximately $55.5 million 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 purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities.

On November 22, 2016, SN Cotulla and SN Palmetto completed the Production Asset Transaction for cash consideration of approximately $24.2 million after normal and customary post-closing adjustments. The purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities. The Production Asset Transaction included the disposition of working interests in 23 producing Eagle Ford wellbores located in Dimmit and Zavala counties in South Texas together with escalating working interests in an additional 11 producing wellbores located in the Palmetto Field in Gonzales County, Texas to SNMP. The effective date of the Production Asset Transaction is July 1, 2016.

On July 5, 2016, SN Midstream completed the Carnero Gathering Disposition for a purchase price of approximately $37.0 million. In addition, SNMP assumed the remaining capital commitments to Carnero Gathering, a joint venture that is 50% owned by Targa, estimated on the transaction closing date to be approximately $7.4 million, and SNMP is required to pay SN Midstream a monthly earnout based on gas received at Carnero Gathering's receipt points from SN Catarina and gas delivered and processed at the Raptor Gas Processing Facility by other producers.

In January 2017, we announced a capital budget of $425 million to $475 million. We now anticipate our capital spending to be between $525 million and $550 million for the full year. The increase in capital spending when compared to prior guidance is a result of approximately $20 million in leasing, enhanced completions, longer laterals, and service cost inflation. The vast majority of leasing done this year was associated with the Company's Javelina acreage position, which was sold in September for $105 million.

Basis of Presentation

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

Core Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale, where, as of September 30, 2017, we had assembled over 286,000 net leasehold acres representing an approximate 59% average working interest and have over 7,500 gross (3,600 net) locations for potential future drilling. For the year 2017, we plan to invest substantially all 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. We anticipate drilling, completion and facilities costs on our acreage to average between $3.0 million and $5.0 million per well. The variability in the cost is largely a factor of lateral lengths, which can vary from approximately 4,400 feet to approximately 10,000 feet. Current estimated ultimate recovery (“EUR”) per well in the Comanche area is expected to range between 600 MBoe and 700 MBoe. We have identified greater than 4,000 gross (1,000 net) Eagle Ford locations for potential future drilling on our Comanche area.

In the Comanche area, we have a drilling obligation beyond other requirements in the leases to maintain the acrage position that requires drilling 60 wells in each annual period commencing on September 1, 2017 and continuing thereafter until September 1, 2022. Up to 30 wells drilled 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 September 30, 2017, 10 wells had been drilled towards the 60 well commitment that will end on August 31, 2018. In addition, 85 drilled-but-uncompleted wells (“DUCs”) acquired as part of the Comanche Acquisition had been completed, of which 83

Table of Contents

had been brought online. These DUCs do not count toward the annual development agreement. For the year 2017, our current capital budget and plans include the drilling of at least the minimum number of wells to maintain access to such undeveloped acreage in the Comanche area.

In the Catarina area, we have approximately 106,000 net acres in Dimmit, LaSalle and Webb Counties, Texas representing a 100% working interest. We anticipate drilling, completion and facilities costs on our acreage to be between $3.0 million and $4.5 million per well based on our current estimates and historical well costs. Current EUR per well in the Catarina area is expected to range between 400 MBoe and 1,200 MBoe. We have identified greater than 1,100 gross (1,100 net) locations for potential future drilling on our Catarina acreage.

In the Catarina area, we also have a drilling obligation 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. By exceeding the 50 well annual drilling commitment in the 2 prior years by 20 wells and 18 wells, respectively, the Company maximized the allowable 30 well bank that can be applied towards the current annual drilling commitment period. As of September 30, 2017, SN had drilled 4 wells in addition to the 30 wells banked towards the annual well commitment in the Catarina area that will extends from July 1, 2017 to June 30, 2018.

In our Maverick area, we have approximately 112,000 net acres in Dimmit, Frio, LaSalle, and Zavala Counties, Texas representing an average working interest of approximately 96%. We believe that our Maverick acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $3.0 million and $4.0 million per well based on our current estimates and historical well costs. Current EUR per well in the Maverick area is expected to range between 300 MBoe and 400 MBoe. We have identified up to 1,100 gross (1,000 net) locations for potential future drilling on our Maverick area.

In our Palmetto area, we have approximately 7,600 net acres in Gonzales County, Texas representing an average working interest of approximately 49%. We believe that our Palmetto acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 million and $6.0 million per well based on our current estimates and historical well costs. Current EUR per well in the Palmetto area is expected to range between 350 MBoe and 600 MBoe. We have identified greater than 400 gross (200 net) locations for potential future drilling in our Palmetto area.

Tuscaloosa Marine Shale

In August 2013, we acquired approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS for cash and shares of our common stock (the “TMS Transaction”). In connection with the TMS Transaction, we established an area of mutual interest ("AMI") in the TMS with SR, which transaction included a carry on drilling costs for up to 6 gross (3 net) wells. As part of the TMS Transaction, we acquired all of the working interests in the AMI owned at closing from three sellers (two third parties and one related party of the Company, SR), resulting in our owning an undivided 50% working interest across the AMI through the TMS formation. As of September 30, 2017, the AMI held rights to approximately 59,500 gross (45,500 net) acres, of which we owned approximately 33,000 net acres.

The TMS development is currently challenged due to high well costs and depressed commodity prices. We believe that the TMS play has significant development potential and still has significant upside as changes in technology, commodity prices, and service prices occur.

Recent Developments

Javelina Disposition

On September 19, 2017, the Company completed the Javelina Disposition for approximately $105 million in cash. Consideration received from the Javelina Disposition was based on an August 1, 2017 effective date and is subject to normal and customary post-closing adjustments. Assets conveyed pursuant to the Javelina Disposition consist of approximately 68,000 undeveloped net acres located in LaSalle and Webb Counties, Texas. The Company had acquired this acreage through leasing over the previous 12 months at a cost of approximately $31 million. Typically, sales of oil and gas properties are accounted for as adjustments to oil and natural gas properties with no gain or loss recognized.

Table of Contents

However, in circumstances where treating a sale like a normal retirement would result in a significant change in the Company's amortization rate, judgment should be applied. The Company determined that adjustments to capitalized costs for the Javelina Disposition would not cause a significant change in the Company's amortization rate. As such, the Company did not record any gains or losses as a result of the Javelina Disposition.

Comanche Integration

Integration of the Comanche Assets continued during the third quarter 2017. To date, the Company has brought 85 wells on-line since we closed the transaction on March 1, 2017, including 41 wells during the third quarter and 2 wells in early October 2017. In addition, there are currently 103 wells awaiting completion within the Comanche Assets. With the Comanche Assets strategically located adjacent to our existing Catarina assets, we anticipate substantial operating synergies and other benefits arising from the scale and concentration of our expanded Eagle Ford position. Our continued focus on the Western Eagle Ford, expertise at multi-bench development and efficient cost structure provide us with opportunities to create significant value from the Comanche Assets. With the potential to duplicate the cost structure of our Catarina and Maverick operations throughout the Comanche Assets, we expect to further improve operating efficiencies while enhancing our capability to achieve sustainability of well cost reductions over time.

Outlook

While capital markets have shown signs of improvement recently, commodity price volatility continues to influence our industry and operating environment. As a result, 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. In this environment, the Company continues to evaluate the possibility of certain non-core divestitures and is carefully managing its capital spending and operating activities in order to preserve liquidity. The Company maintains significant operational and financial flexibility to respond to changes in market and operating conditions, and we anticipate our 2018 capital spending, as compared to 2017, to be $75 million to $100 million lower, better balancing cash flows.

We expect to use internally generated cash flow from operations, a portion of our cash on hand, and a combination of funds raised through the sale of certain non-core assets and/or borrowing capacity, to fund our remaining 2017 capital expenditures. We continuously evaluate our capital spending, operating and funding activities in light of realized commodity prices and the results of our operations, and may make further adjustments to our capital spending program and related financing plans as warranted. In addition, we continuously review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

For the 12-month period ended September 30, 2017, the oil price (WTI Cushing) used in the SEC methodology for calculating PV 10 and Standardized Measures, and for performing impairment tests under the full cost method, which is calculated as the unweighted arithmetic average of the first of the month reported price for the 12-month historical period, was $49.81 per barrel. The average natural gas price (Henry Hub) calculated in the same manner was $3.01 per MMBtu. At these price levels, SEC prices for oil have increased approximately 17% and increased for natural gas approximately 21% since December 31, 2016.

Table of Contents

Results of Operations

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

Revenue and Production

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

	Three Months Ended September 30,		Increase (Decrease) 2017 vs 2016		
	2017	2016		%	
Net Production:					
Oil (MBbl)	2,033	1,562	471	30	%
NGLs (MBbl)	2,289	1,413	876	62	%
Natural gas (MMcf)	14,795	10,595	4,200	40	%
Total oil equivalent (MBoe)	6,788	4,741	2,047	43	%
Average Sales Price Excluding Derivatives(1):					
Oil ($ per Bbl)	$ 45.02	$ 40.99	$ 4.03	10	%
NGLs ($ per Bbl)	21.38	13.81	7.57	55	%
Natural gas ($ per Mcf)	3.00	2.95	0.05	2	%
Oil equivalent ($ per Boe)	$ 27.22	$ 24.22	$ 3.00	12	%
Average Sales Price Including Derivatives(2):					
Oil ($ per Bbl)	$ 49.18	$ 57.18	$ (8.00)	(14)	%
NGLs ($ per Bbl)	21.38	13.81	7.57	55	%
Natural gas ($ per Mcf)	3.14	3.22	(0.08)	(2)	%
Oil equivalent ($ per Boe)	$ 28.77	$ 30.15	$ (1.38)	(5)	%
Revenues(1):					
Oil sales	$ 91,541	$ 64,041	$ 27,500	43	%
NGL sales	48,949	19,511	29,438	151	%
Natural gas sales	44,316	31,255	13,061	42	%
Total revenues	$ 184,806	$ 114,807	$ 69,999	61	%

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

50

Table of Contents

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

	Three Months Ended September 30,	
	2017	2016
Production:		
Oil – MBbl		
Comanche	912	—
Catarina	741	852
Maverick	307	275
Cotulla	6	188
Palmetto	59	80
Marquis	2	157
TMS / Other	6	10
Total	2,033	1,562
NGLs – MBbl		
Comanche	981	—
Catarina	1,271	1,291
Maverick	21	6
Cotulla	—	60
Palmetto	16	20
Marquis	—	36
TMS / Other	—	—
Total	2,289	1,413
Natural gas – MMcf		
Comanche	5,470	—
Catarina	9,128	9,911
Maverick	113	42
Cotulla	—	355
Palmetto	87	126
Marquis	(3)	159
TMS / Other	—	2
Total	14,795	10,595
Net production volumes:		
Total oil equivalent (MBoe)	6,788	4,741
Average daily production (Boe/d)	73,783	51,533
Average Sales Price (1):		
Oil ($ per Bbl)	$ 45.02	$ 40.99
NGLs ($ per Bbl)	$ 21.38	$ 13.81
Natural gas ($ per Mcf)	$ 3.00	$ 2.95
Oil equivalent ($ per Boe)	$ 27.22	$ 24.22
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 10.62	$ 8.23
Production and ad valorem taxes	$ 1.67	$ 0.83
General and administrative	$ 2.16	$ 5.68

Adjusted G&A per Boe (2)(3)	$ 1.77	$ 3.69
Depreciation, depletion, amortization and accretion	$ 7.64	$ 7.94
Impairment of oil and natural gas properties	$ —	$ 12.57

(1) Excludes the impact of derivative instruments.

(2) For the three months ended September 30, 2017 and 2016, Adjusted general and administrative ("G&A") expense excludes non-cash stock-based compensation expense of approximately $0.9 million ($0.13 per Boe) and $8.3 million ($1.75 per Boe), respectively.

Table of Contents

(3) For the three months ended September 30, 2017 and 2016, Adjusted G&A expense excludes acquisition and divestiture costs included in G&A expense of approximately $1.8 million ($0.26 per Boe) and $1.1 million ($0.24 per Boe), respectively.

The table above in addition to other areas throughout this Quarterly Report on Form 10-Q contains disclosures of G&A expenses excluding expenses related to stock-based compensation expense and certain costs related to acquisitions and divestitures, which is referred to as "Adjusted G&A." Adjusted G&A is a "non-GAAP financial measure," as defined in SEC rules. Please see below "Non-GAAP Financial Measures—Adjusted G&A and Adjusted G&A per Boe," for a reconciliation of G&A and G&A per Boe to Adjusted G&A and Adjusted G&A per Boe, respectively.

Net Production. Production increased from 4,741 MBoe for the three months ended September 30, 2016 to 6,788 MBoe for the three months ended September 30, 2017 mainly due to production from the Comanche wells. The number of gross wells producing at the period end and the net production for the periods were as follows:

	Three Months Ended September 30,			
	2017		2016	
	# Wells	MBoe	# Wells	MBoe
Comanche	1,518	2,805	—	—
Catarina	381	3,533	311	3,795
Maverick	50	347	—	288
Cotulla	—	6	153	308
Palmetto	84	89	76	120
Marquis	—	2	103	220
TMS / Other	14	6	14	10
Total	2,047	6,788	657	4,741

For the three months ended September 30, 2017, 30% of our production was oil, 34% was NGLs and 36% was natural gas compared to the three months ended September 30, 2016 production that was 33% oil, 30% NGLs and 37% natural gas. The production mix is relatively consistent between the periods due to the similar proportion of oil, NGLs and natural gas production from our producing properties.

Revenues. Oil, NGLs, and natural gas sales revenues totaled $184.8 million and $114.8 million for the three months ended September 30, 2017 and 2016, respectively. Oil, NGLs, and natural gas sales revenues for the three months ended September 30, 2017 increased $27.5 million, $29.4 million and $13.1 million, respectively, as compared to the three months ended September 30, 2016.

The tables below provide an analysis of the impacts of changes in production volumes and average realized prices between the periods on our revenues from the quarter ended September 30, 2016 to the quarter ended September 30, 2017 (in thousands, except average sales price). The increase in revenue from the quarter ended September 30, 2016

Table of Contents

to the quarter ended September 30, 2017 is primarily attributable to the increase in commodity price and an increase in production volume.

	Three Months Ended September 30, 2017	2016	Production	Three Months Ended September 30, 2016	Revenue Increase (Decrease)
	Production Volume	Production Volume	Volume Difference	Average Sales Price	due to Production
Oil (MBbl)	2,033	1,562	471	$ 40.99	$ 19,310
NGLs (MBbl)	2,289	1,413	876	$ 13.81	$ 12,106
Natural gas (MMcf)	14,795	10,595	4,200	$ 2.95	$ 12,388
Total oil equivalent (MBoe)	6,788	4,741	2,047	$ 24.22	$ 43,804

	Three Months Ended September 30, 2017	2016	Average	Three Months Ended September 30, 2017	Revenue Increase (Decrease)
	Average Sales Price	Average Sales Price	Sales Price Difference	Production Volume	due to Price
Oil (MBbl)	$ 45.02	$ 40.99	$ 4.03	2,033	$ 8,190
NGLs (MBbl)	$ 21.38	$ 13.81	$ 7.57	2,289	$ 17,332
Natural gas (MMcf)	$ 3.00	$ 2.95	$ 0.05	14,795	$ 673
Total oil equivalent (MBoe)	$ 27.22	$ 24.22	$ 3.00	6,788	$ 26,195

Additionally, a 10% increase in our average realized sales prices, excluding the impact of derivatives, would have increased our revenues for the three months ended September 30, 2017 by approximately $18.5 million, and a 10% decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the three months ended September 30, 2017 by approximately $18.5 million.

Operating Costs and Expenses

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

	Three Months Ended September 30,		Increase (Decrease) 2017 vs 2016	
	2017	2016	$	%
Operating Costs and Expenses:				
Oil and natural gas production expenses	$ 72,056	$ 38,997	$ 33,059	85 %
Production and ad valorem taxes	11,346	3,921	7,425	189 %
Depreciation, depletion, amortization and accretion	51,859	37,651	14,208	38 %
Impairment of oil and natural gas properties	—	59,582	(59,582)	(100) %
General and administrative	14,665	26,936	(12,271)	(46) %
Total operating costs and expenses	149,926	167,087	(17,161)	(10) %
Interest income and other expense	(285)	153	(438)	*
Loss on sale of oil and natural gas properties	(2,074)	—	(2,074)	*
Interest expense	(35,686)	(31,797)	(3,889)	12 %
Earnings from equity investments	102	463	(361)	(78) %
Net gains (losses) on commodity derivatives	(41,719)	18,640	(60,359)	*
Income tax expense	—	(1,441)	1,441	*

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 day-to-day costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production

Table of Contents

expenses increased 85% to approximately $72.1 million for the three months ended September 30, 2017 as compared to $39.0 million for the same period in 2016. The 85% increase in oil and natural gas production expenses in the third quarter 2017 compared to the same period of 2016 is primarily attributable to the increase in operating activity related to the wells in the Comanche area. Our average production expenses increased from $8.23 per Boe during the three months ended September 30, 2016 to $10.62 per Boe for the three months ended September 30, 2017. This increase was due primarily to the increase in marketing and transportation costs related to contracts signed in connection with the Comanche Acquisition and the increase in gathering and transportation costs associated with the gathering agreement contract with SNMP. While we expect our oil and natural gas production expenses to increase as we add producing wells and vendor costs increase, we expect to continue our efficient operation of our properties.

Production and Ad Valorem Taxes. Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes totaled $11.3 million and $3.9 million for the three months ended September 30, 2017 and 2016, respectively. The increase in production and ad valorem taxes in the third quarter 2017 compared to the same period in 2016 was primarily due to the increase in production taxes based on the corresponding increase in revenue during the period. In addition, there was an increase in ad valorem taxes due to the addition of the Comanche Assets in March 2017. Our average production and ad valorem taxes increased from $0.83 per Boe during the three months ended September 30, 2016 to $1.67 per Boe for the three months ended September 30, 2017, which is mainly due to the increase in property values during 2017 as compared to 2016 due to the rise in commodity prices during the period.

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

Our DD&A expense increased $14.2 million from $37.7 million ($7.94 per Boe) for the three months ended September 30, 2016 to $51.9 million ($7.64 per Boe) for the three months ended September 30, 2017. The majority of the increase in DD&A is related to the increase in production from the wells acquired in the Comanche Acquisition. This was slightly offset by the decrease in the depletion rate due to the cumulative effect of full cost ceiling impairments recorded since the second quarter 2016 and the decrease in the full cost pool related to the Cotulla Disposition and Production Asset Transaction in 2016 and the Javelina Disposition in 2017. Increased production during the three months ended September 30, 2017 as compared to the same period in 2016 resulted in a $15.8 million increase in depletion expense and the decrease in the depletion rate resulted in a $1.1 million decrease in depletion expense.

Impairment of Oil and Natural Gas Properties. We utilize the full cost method of accounting for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based on the projected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non cash impairment expense. We did not record a full cost ceiling test impairment for the three months ended September 30, 2017. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. We recorded a full cost ceiling test impairment after income taxes of $59.6 million for the three months ended September 30, 2016. While there is a possibility that the Company will incur impairments to our full cost pool in 2017, factors impacting the full cost ceiling test impairment calculation have not yet been determined. Based upon the NYMEX first-day-of-the-month prices for October 2017, along with the NYMEX WTI forward-looking price deck for November and December 2017, the Company estimates the average 12 month trailing first-day-of-the-month prices ending September 30, 2017 to increase from the current quarter ended.

General and Administrative Expenses. Our G&A expenses totaled $14.7 million for the three months ended September 30, 2017 compared to $26.9 million for the same period in 2016. This decrease was due primarily a decrease in legal, consulting and professional fees and a decrease in our non-cash stock-based compensation expense. Our G&A

Table of Contents

expenses per Boe decreased from $5.68 per Boe for the three months ended September 30, 2016 to $2.16 per Boe for the three months ended September 30, 2017.

For the three months ended September 30, 2017 and 2016, we recorded non-cash stock based compensation expense (settled in common shares) of approximately $0.9 million ($0.13 per Boe) and $8.3 million ($1.75 per Boe), respectively. The decrease in the non-cash stock-based compensation expense amount was caused by a decrease in the Company's stock price offset slightly by an increase in the awards outstanding and the associated amortization expense recognized. Because 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, the Company's decrease in stock price will cause a decrease to the stock based compensation expense recognized during the quarter.

We recorded costs associated with significant acquisitions and divestitures that are included in G&A of $1.8 million ($0.26 per Boe) for the three months ended September 30, 2017 primarily related to the Comanche Acquisition. Costs associated with the significant acquisition or divestitures included in G&A for the three months ended September 30, 2016 totaled approximately $1.1 million ($0.24 per Boe) primarily related to the Carnero Processing Disposition.

Adjusted G&A, excluding non-cash stock based compensation expense and acquisition and divestiture costs included in G&A, totaled $12 million ($1.77 per Boe) and $17.5 million ($3.69 per Boe), for the three months ended September 30, 2017 and 2016, respectively.

Other Income (Expense). For the three months ended September 30, 2017, other expense totaled $285 thousand. This is compared to the three months ended September 30, 2016, for which other income totaled $153 thousand. The other expense incurred during the three months ended September 30, 2017 relates primarily to a $2.8 million loss associated with the decrease in fair value of the investment in SNMP and the investment in Lonestar of $1.2 million and $1.6 million, respectively. In addition, there was a distribution of $1.1 million from the quarterly distribution on the investment in SNMP, a $1.8 million gain on embedded derivatives and $0.4 million in other expenses. For the three months ended September 30, 2016, other income primarily related to interest income.

Interest Expense. For the three months ended September 30, 2017, interest expense totaled $35.7 million and included $3.3 million in amortization of debt issuance costs. This is compared to the three months ended September 30, 2016, for which interest expense totaled $31.8 million and included $2.0 million in amortization of debt issuance costs. The interest expense incurred during the three months ended September 30, 2017 and September 30, 2016 is primarily related to the 7.75% Notes issued in June and September 2013, the 6.125% Notes issued in June and September 2015 and, for 2017, the SN UnSub Credit Agreement outstanding debt incurred in March 2017.

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 expense. During the three months ended September 30, 2017, we recognized a total loss of $41.7 million on our commodity derivative contracts primarily related mark-to-market losses on oil and natural gas derivatives of $47.8 million and $4.5 million, respectively. These losses were primarily the result of increases in commodity prices from the time the trades were entered until the end of the period. In addition, there were settlement gains on oil and natural gas derivatives of $8.5 million and $2.1 million, respectively. Settlement gains and losses are the result of the decrease or increase, respectively, in commodity prices from the time the trades were entered until the time of cash settlement for trades that liquidated by their terms during the current period.

During the three months ended September 30, 2016, we recognized a total gain of $18.6 million on our commodity derivative contracts primarily related to settlement gains on oil and natural gas derivatives of $25.3 million and $2.8 million, respectively. These gains were primarily the result of decreases in commodity prices from the time the trades were entered to the settlement period. In addition, we recognized a mark-to-market gain on natural gas derivatives of $5.1 million due to a decrease in the commodity price during the quarter. These gains were slightly offset by mark-to-market losses on oil derivatives of $14.6 million as a result of the increase in the commodity price during the quarter.

Income Tax Benefit. For the three months ended September 30, 2017, the Company did not record an income tax benefit. Our effective tax rate for the three months ended September 30, 2017 was approximately (0.0)% compared to the maximum statutory rate of 35%. The difference between the statutory rate and the Company’s effective tax rate is

Table of Contents

primarily related to a valuation allowance recorded during the period. For the three months ended September 30, 2016, the Company recorded income tax expense of approximately $1.4 million. Due to the full cost ceiling impairment recorded, the Company was in a net loss position for the quarter but had current income tax expense related to adjustments for immaterial differences on the alternative minimum tax calculation from the 2015 income tax return filed in September 2016 to the accrual for the 2015 income taxes recorded in December 2015. Our effective tax rate for the three months ended September 30, 2016 was approximately (0.5)% compared to the maximum statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is related to a valuation allowance recorded during the period.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Revenue and Production

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

	Nine Months Ended September 30,		Increase (Decrease) 2017 vs 2016		
	2017	2016		%	
Net Production:					
Oil (MBbl)	5,657	4,836	821	17	%
NGLs (MBbl)	5,790	4,620	1,170	25	%
Natural gas (MMcf)	40,065	33,092	6,973	21	%
Total oil equivalent (MBoe)	18,125	14,971	3,154	21	%
Average Sales Price Excluding Derivatives(1):					
Oil ($ per Bbl)	$ 45.24	$ 35.67	$ 9.57	27	%
NGLs ($ per Bbl)	19.50	12.24	7.26	59	%
Natural gas ($ per Mcf)	3.13	2.31	0.82	35	%
Oil equivalent ($ per Boe)	$ 27.27	$ 20.41	$ 6.86	34	%
Average Sales Price Including Derivatives(2):					
Oil ($ per Bbl)	$ 48.14	$ 54.89	$ (6.75)	(12)	%
NGLs ($ per Bbl)	19.50	12.24	7.26	59	%
Natural gas ($ per Mcf)	3.09	3.01	0.08	3	%
Oil equivalent ($ per Boe)	$ 28.09	$ 28.16	$ (0.07)	(0)	%
Revenues(1):					

Oil sales	$ 255,913	$ 172,509	$ 83,404	48	%
Natural gas liquids sales	112,922	56,535	56,387	100	%
Natural gas sales	125,518	76,547	48,971	64	%
Total revenues	$ 494,353	$ 305,591	$ 188,762	62	%

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

56

Table of Contents

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

	Nine Months Ended September 30, 2017	2016
Production:		
Oil - MBbl		
Comanche	2,055	—
Catarina	2,304	2,721
Maverick	833	565
Cotulla	25	669
Palmetto	195	291
Marquis	225	554
TMS / Other	20	36
Total	5,657	4,836
NGLs - MBbl		
Comanche	2,108	—
Catarina	3,553	4,231
Maverick	40	10
Cotulla	1	192
Palmetto	40	64
Marquis	48	123
TMS / Other	—	—
Total	5,790	4,620
Natural gas - MMcf		
Comanche	12,355	—
Catarina	27,061	30,948
Maverick	220	67
Cotulla	(9)	1,148
Palmetto	232	404
Marquis	208	518
TMS / Other	(2)	7
Total	40,065	33,092
Net production volumes:		
Total oil equivalent (MBoe)	18,125	14,971
Average daily production (Boe/d)	66,392	54,639
Average Sales Price (1):		
Oil ($ per Bbl)	$ 45.24	$ 35.67
NGLs ($ per Bbl)	$ 19.50	$ 12.24
Natural gas ($ per Mcf)	$ 3.13	$ 2.31
Oil equivalent ($ per Boe)	$ 27.27	$ 20.41
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 9.77	$ 8.59

Production and ad valorem taxes	$ 1.47	$ 0.94
General and administrative	$ 6.17	$ 4.70
Adjusted G&A per Boe (2)(3)	$ 3.63	$ 3.38
Depreciation, depletion, amortization and accretion	$ 7.50	$ 8.55
Impairment of oil and natural gas properties	$ —	$ 11.29

Table of Contents

(1) Excludes the impact of derivative instruments.

(2) For the nine months ended September 30, 2017 and 2016, Adjusted G&A excludes non-cash stock-based compensation expense of approximately $17.3 million ($0.96 per Boe) and $17.9 million ($1.20 per Boe), respectively.

(3) For the nine months ended September 30, 2017 and 2016, Adjusted G&A expense excludes acquisition and divestiture costs included in G&A expense of approximately $28.7 million ($1.58 per Boe) and $1.8 million ($0.12 per Boe), respectively.

Net Production. Production increased from 14,971 MBoe for the nine months ended September 30, 2016 to 18,125 MBoe for the nine months ended September 30, 2017 due to the addition of the Comanche Assets, offset by a decrease in other areas as a result of divestitures during the period. The number of gross wells producing at the period end and the production for the periods were as follows:

	Nine Months Ended September 30,			
	2017		2016	
	# Wells	MBoe	# Wells	MBoe
Comanche	1,518	6,222	—	—
Catarina	381	10,367	311	12,110
Maverick	50	910	—	586
Cotulla	—	25	153	1,053
Palmetto	84	274	76	422
Marquis	—	308	103	763
TMS / Other	14	19	14	37
Total	2,047	18,125	657	14,971

For the nine months ended September 30, 2017, 31% of our production was oil, 32% was NGLs and 37% was natural gas compared to the nine months ended September 30, 2016 production that was 32% oil, 31% NGLs and 37% natural gas. The production mix is consistent between the periods due to the similar proportion of oil, NGLs and natural gas production from our producing properties.

Revenues. Oil, NGLs, and natural gas sales revenues totaled approximately $494.4 million and $305.6 million for the nine months ended September 30, 2017 and 2016, respectively. Oil, NGL and natural gas sales revenues for the nine months ended September 30, 2017 increased $83.4 million, $56.4 million and $49.0 million, respectively, as compared to the nine months ended September 30, 2016.

The tables below provide an analysis of the impacts of changes in production volumes and average realized prices on our revenues for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2017 (in thousands, except average sales price). The increase in average realized prices from the nine months ended September 30, 2016 to the nine months ended September 30, 2017 can be attributed to the increase in commodity prices.

Table of Contents

	Nine Months Ended September 30, 2017 Production Volume	2016 Production Volume	Production Volume Difference	Nine Months Ended September 30, 2016 Average Sales Price	Revenue Increase due to Production
Oil (MBbl)	5,657	4,836	821	$ 35.67	$ 29,294
NGLs (MBbl)	5,790	4,620	1,170	$ 12.24	$ 14,318
Natural gas (MMcf)	40,065	33,092	6,973	$ 2.31	$ 16,132
Total oil equivalent (MBoe)	18,125	14,971	3,154	$ 20.41	$ 59,744

	Nine Months Ended September 30, 2017 Average Sales Price	2016 Average Sales Price	Average Sales Price Difference	Nine Months Ended September 30, 2017 Production Volume	Revenue Increase due to Price
Oil (MBbl)	$ 45.24	$ 35.67	$ 9.57	5,657	$ 54,110
NGLs (MBbl)	$ 19.50	$ 12.24	$ 7.26	5,790	$ 42,069
Natural gas (MMcf)	$ 3.13	$ 2.31	$ 0.82	40,065	$ 32,839
Total oil equivalent (MBoe)	$ 27.27	$ 20.41	$ 6.86	18,125	$ 129,018

Additionally, a 10% increase in our average realized sales prices, excluding the impact of derivatives, would have increased our revenues for the nine months ended September 30, 2017 by approximately $49.4 million, and a 10% decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the nine months ended September 30, 2017 by approximately $49.4 million.

Operating Costs and Expenses

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

	Nine Months Ended September 30, 2017	2016	Increase (Decrease) 2017 vs 2016 $	%
Operating Costs and Expenses:				
Oil and natural gas production expenses	$ 177,129	$ 128,609	$ 48,520	38 %
Production and ad valorem taxes	26,669	14,052	12,617	90 %

Depreciation, depletion, amortization and accretion	135,916	127,959	7,957	6	%
Impairment of oil and natural gas properties	—	169,046	(169,046)	(100)	%
General and administrative	111,843	70,399	41,444	59	%
Total operating costs and expenses	451,557	510,065	(58,508)	(11)	%
Interest income and other expense	4,139	433	3,706	*	
Gain on sale of oil and natural gas properties	10,202	—	10,202	*	
Interest expense	(104,672)	(95,225)	(9,447)	10	%
Earnings from equity investments	779	3,154	(2,375)	(75)	%
Net gains (losses) on commodity derivatives	56,777	(17,353)	74,130	*	
Income tax benefit (expense)	1,208	(1,441)	2,649	(184)	%

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased 38% to approximately $177.1 million for the nine months ended September 30, 2017 as compared to $128.6 million for the same period in 2016. The increase in oil and natural gas production expenses in the third quarter 2017 compared to the same period of 2016 is attributable to our increased production activities in the Comanche area offset by decreases in production resulting from divestitures during the period. Our average production expenses increased from $8.59 per Boe during the nine months ended September 30, 2016 to $9.77 per Boe for the nine months ended September 30, 2017. This increase was due primarily to the increase in marketing and transportation costs related to contracts signed in connection with the Comanche Acquisition and the increase in gathering and transportation costs associated with the gathering agreement contract with SNMP. While we expect our oil and natural gas production expenses to increase as we add producing wells, we expect to continue our efficient operation of our properties.

Production and Ad Valorem Taxes. Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes totaled $26.7 million and $14.1 million for the nine months ended September 30, 2017 and 2016, respectively. The increase in production taxes in the first nine months of 2017 compared to the same period in 2016 was primarily due to the corresponding increase in revenue during the period. In addition, there was an increase in ad valorem taxes due to the addition of the Comanche Assets in March 2017. Our average production and ad valorem taxes increased from $0.94 per Boe during the nine months ended September 30, 2016 to $1.47 per Boe for the nine months ended September 30, 2017. This increase in rate is attributable to the revised estimates for ad valorem taxes recorded during the second quarter 2016, causing a lower ad valorem tax expense during the nine months ended September 30, 2016.

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

Our DD&A expense increased $7.9 million from $128.0 million ($8.55 per Boe) for the nine months ended September 30, 2016 to $135.9 million ($7.50 per Boe) for the nine months ended September 30, 2017. The majority of the increase in DD&A is related to the increase in production as a result of the Comanche Acquisition in 2017, offset by a decrease in the depletion rate as a result of reductions to the full cost pool related to the Marquis and Javelina Dispositions in 2017. Higher production during the nine months ended September 30, 2017 as compared to the same period in 2016 resulted in a $27.0 million increase in depletion expense and the decrease in the depletion rate resulted in a $19.0 million decrease in depletion expense.

Impairment of Oil and Natural Gas Properties. We utilize the full cost method of accounting for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the “ceiling,” based on the projected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non cash impairment expense. We did not record a full cost ceiling test impairment for the nine months ended September 30, 2017. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. We recorded a full cost ceiling test impairment after income taxes of $169.0 million for the nine months ended September 30, 2016. Based upon the NYMEX first-day-of-the-month prices for October 2017, along with the NYMEX WTI forward-looking price deck for November and December 2017, the Company estimates the average 12 month trailing first-day-of-the-month prices ending December 31, 2017 to increase from the current quarter ended.

General and Administrative Expenses. Our G&A expenses totaled $111.8 million for the nine months ended September 30, 2017 compared to $70.4 million for the same period in 2016. This increase was due primarily to additional legal, consulting and professional fees and added personnel at SOG performing services for the Company associated with the Comanche Acquisition and operations. Our G&A expenses per Boe increased from $4.70 per Boe for the nine months ended September 30, 2016 to $6.17 per Boe for the nine months ended September 30, 2017.

For the nine months ended September 30, 2017 and 2016, we recorded non cash stock based compensation expense (settled in common shares) of approximately $17.3 million ($0.96 per Boe) and $17.9 million ($1.20 per Boe), respectively. The increase in the stock-based compensation expense amount was caused by an increase in awards

Table of Contents

outstanding and the associated amortization expense recognized in addition to the PARS awards granted in the first and second quarters of 2016 that had accelerated vestings from market performance conditions that occurred during the first and second quarters of 2017, offset by a decrease in the Company's stock price. Because 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, the Company's decrease in stock price will cause a decrease to the stock based compensation expense recognized during the quarter.

We recorded costs associated with significant acquisitions and divestitures that are included in G&A of $28.7 million ($1.58 per Boe) for the nine months ended September 30, 2017, primarily related to the Comanche Acquisition. Costs associated with the significant acquisition or divestitures included in G&A for the nine months ended September 30, 2016 totaled approximately $1.8 million ($0.12 per Boe), primarily related to the Carnero Processing Disposition.

Adjusted G&A, excluding non-cash stock based compensation expense and acquisition and divestiture costs included in G&A, totaled $65.8 million ($3.63 per Boe) and $50.7 million ($3.38 per Boe), for the nine months ended September 30, 2017 and 2016, respectively.

Interest Expense. For the nine months ended September 30, 2017, interest expense totaled $104.7 million and included $9.5 million in amortization of debt issuance costs. This is compared to the nine months ended September 30, 2016, for which interest expense totaled $95.2 million and included $5.9 million in amortization of debt issuance costs. The interest expense incurred during the nine months ended September 30, 2017 and 2016 is primarily related to the 7.75% Notes issued in June and September 2013, the 6.125% Notes issued in June and September 2015 and, for 2017, the SN UnSub Credit Agreement outstanding debt incurred in March 2017.

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 expense. During the nine months ended September 30, 2017, we recognized a total gain of $56.7 million on our commodity derivative contracts primarily related to mark-to-market gains on commodity derivatives of $41.9 million, associated with the decrease in oil and natural gas prices during the three quarters of 2017. In addition, the Company had gains from settlements of commodity derivative contracts of $14.8 million. These gains were primarily the result of decreases in commodity prices from the time the trades were entered until the time of cash settlement for trades that liquidated by their terms during the current period. During the nine months ended September 30, 2016, we recognized a net loss of $17.4 million on our commodity derivative contracts primarily related to mark-to-market losses on oil and natural gas derivatives of $106.4 million and $27.0 million, respectively, associated with the increase in oil and natural prices from December 31, 2015 to September 30, 2016. These mark-to-market losses were offset by settlements of commodity derivative contracts of $116.0 million. These gains were primarily the result of decreases in commodity prices from the time the trades were entered until the time of cash settlement during the current period.

Income Tax Benefit. For the nine months ended September 30, 2017, the Company recorded an income tax benefit of approximately $1.2 million. During the period, the Company issued warrants to purchase common stock (as described in Note 13, “Stockholders’ and Mezzanine Equity” of Part 1, Item 1. Financial Statements) that had a day one difference in estimated fair value for book and tax accounting purposes, which caused an income tax benefit during the period. Our effective tax rate for the nine months ended September 30, 2017 was approximately (12.1)% compared to the maximum statutory rate of 35%. The difference between the statutory rate and the Company’s effective tax rate is primarily related to the recording of certain deferred tax liabilities associated with the Comanche Acquisition that were recorded directly to equity, whereas the correlating movement in the valuation allowance was recorded directly to income tax expense. For the nine months ended September 30, 2016, the Company recorded income tax expense of approximately $1.4 million. Due to the full cost ceiling impairment recorded, the Company was in a net loss position for the quarter but had current income tax expense related to adjustments for immaterial differences on the alternative minimum tax calculation for the 2015 income tax return filed in September 2016 to the accrual for 2015 income taxes recorded in December 2015. Our effective tax rate for the nine months ended September 30, 2016 was (0.5)% compared to the maximum statutory rate of 35%. The difference between the statutory rate and the Company’s effective tax rate is related to a valuation allowance recorded during the period.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. GAAP requires our management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The

Table of Contents

selection and application of those policies requires our management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of September 30, 2017, our critical accounting policies were consistent with those discussed in our 2016 Annual Report.

Use of Estimates

The condensed consolidated financial statements are prepared in conformity with U.S. GAAP, which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the depletion and impairment of oil and natural gas properties, the evaluation of unproved properties for impairment, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

Liquidity and Capital Resources

As of September 30, 2017, we had approximately $174.2 million in cash and cash equivalents, $300 million in available borrowing capacity at the elected commitment amount under the Second Amended and Restated Credit Agreement, and $154.5 million in available borrowing capacity at the elected commitment amount under the UnSub Credit Agreement, resulting in total liquidity of approximately $628.7 million. For a description of current and previous credit agreements along with the indentures covering our Senior Notes refer to Note 6, "Long Term Debt" of Part 1, Item 1. Financial Statements.

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.

In January 2017, we announced a capital budget of $425 million to $475 million. We now anticipate our capital spending to be between $525 million and $550 million for the full year. The increase in capital spending when compared to prior guidance is a result of approximately $20 million in leasing, enhanced completions, longer laterals, and service cost inflation. The vast majority of leasing done this year was associated with the Company's Javelina acreage position, which was sold in September for $105 million. The Company maintains significant operational and financial flexibility to respond to changes in market and operating conditions, and we anticipate our 2018 capital spending, as compared to 2017, to be $75 million to $100 million lower, better balancing cash flows.

On February 6, 2017, we closed an underwritten public offering of shares of our common stock and received net proceeds of approximately $135.9 million (after deducting underwriting discounts of approximately $7.8 million). We used the net proceeds of the offering for general corporate purposes, including working capital.

On May 25, 2017, the Company entered the 2017 ATM, which allows us to issue from time to time shares of our common stock up to an aggregate gross amount of $75 million. Sales of our common stock, if any, under the 2017 ATM will be made by any method permitted by law deemed to be an "at the market" offering as defined under the Securities Act of 1933, as amended, including, without limitation, sales made directly on the New York Stock Exchange, on any other existing trading market for our shares of common stock or to or through a market maker or as otherwise agreed by the Company and the sales agent. As of September 30, 2017, we had not issued any shares of our common stock under the 2017 ATM.

Table of Contents

Cash Flows

Our cash flows for the nine months ended September 30, 2017 and 2016 (in thousands) are as follows:

	Nine Months Ended September 30,	
	2017	2016
Cash Flow Data:		
Net cash provided by operating activities	$ 170,734	$ 138,112
Net cash used in investing activities	$ (1,231,380)	$ (236,990)
Net cash provided by (used in) financing activities	$ 732,957	$ (7,641)

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $170.7 million for the nine months ended September 30, 2017 compared to cash provided by operating activities of $138.1 million for the same period in 2016. This increase was primarily related to transaction costs associated with the Comanche Acquisition and a decrease of cash inflows for settlements on commodity derivatives during the current period when compared to the nine months ended September 30, 2016. This decrease was partially offset by higher revenues due to increased production and the impact of higher average commodity prices between these periods.

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

Net Cash Used in Investing Activities. Net cash flows used in investing activities totaled $1.2 billion for the nine months ended September 30, 2017 compared to $237.0 million for the same period in 2016, primarily attributable to purchase of the Comanche Assets for approximately $1.0 billion in March 2017. Capital expenditures for leasehold and drilling activities for the nine months ended September 30, 2017 totaled $351.2 million, primarily associated with bringing 83 gross wells on-line, which included the completion of 85 DUCs acquired in the Comanche Acquisition. We 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, and an additional $105 million for the Javelina Disposition. In addition, we invested $16.3 million in other property and equipment during the nine months ended September 30, 2017.

For the nine months ended September 30, 2016, we incurred capital expenditures for leasehold and drilling activities of $241.3 million, primarily associated with bringing 36 gross wells on-line. The Company invested $28.7 million in the joint ventures with Targa, which was offset by the $37.0 million cash inflows from the sale of the Carnero Gathering interests. In addition, we invested $4.0 million in other property and equipment during the nine months ended September 30, 2016.

Net Cash Provided by (Used in) Financing Activities. Net cash flows provided by financing activities totaled $733.0 million for the nine months ended September 30, 2017 compared to cash outflows related to financing activities of $7.6 million for the same period in 2016. In association with the Comanche Acquisition in March 2017, we entered into the SN UnSub Credit Agreement and issued the SN UnSub Preferred Units for $500 million. From time to time, the Company has borrowed under the Second Amended and Restated Credit Agreement 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 September 30, 2017, no debt was outstanding under the Second Amended and Restated Credit Agreement and all of the elected commitment amount of $300 million was available for future borrowings. Further, as of September 30, 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 $46.1 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 $0.8 million of employee taxes via withholding shares associated with stock-based compensation, which is considered a financing payment under the accounting guidance of ASU 2016-09. During the nine months ended September 30, 2017, we also made payments of $35.7 million for tax distributions to holders of the SN UnSub Preferred Units. The Partnership Agreement provides that tax distributions shall be treated as advances of any amounts holders of the SN UnSub Preferred Units are entitled to receive, and shall be offset against any amounts holders of SN UnSub Preferred Units are entitled to receive.

During the nine months ended September 30, 2016, we made payments of approximately $4.0 million for common stock dividends on our Series A Preferred Stock and Series B Preferred Stock and payments of approximately $1.7 million for deferred financing costs associated with an amendment to the Second Amended and Restated Credit Agreement. In addition, the Company made payments of employee taxes via withholding shares associated with stock-based compensation of approximately $1.9 million.

The $0.8 million and $1.9 million of employee taxes for the nine months ended September 30, 2017 and 2016, respectively, were paid for through open market sales by the employees of vested shares of common stock in connection with the vesting of the stock-based compensation awards triggering the tax obligation, the proceeds of which were remitted to the Company to satisfy that tax obligation, rather than the withholding of shares of common stock by the Company and payment by the Company of the corresponding tax amounts.

Off Balance Sheet Arrangements

As of September 30, 2017, we did not have any off balance sheet arrangements.

Commitments and Contractual Obligations

Refer to Note 16, “Commitments and Contingencies” of Part 1, Item 1. Financial Statements for a description of lawsuits pending against the Company.

There have been no material changes in our contractual obligations during the nine months ended September 30, 2017, other than those disclosed in Note 16, “Commitments and Contingencies” of Part 1, Item 1. Financial Statements.

Non GAAP Financial Measures

Adjusted G&A and Adjusted G&A per Boe

We present Adjusted G&A expense in addition to our reported G&A expense in accordance with U.S. GAAP. Adjusted G&A is reported herein because this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes Adjusted G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs that can vary substantially from company to company and from period to period. Adjusted G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similar titled measures of other companies. We define Adjusted as G&A, less:

- Non-cash stock-based compensation expense; and

- Certain costs related to acquisitions and divestitures.

Table of Contents

The following table presents a reconciliation of our G&A to Adjusted G&A (in thousands, except per Boe data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except per Boe data)			
General and administrative expense	$ 14,665	$ 26,936	$ 111,843	$ 70,399
Less:				
Stock-based compensation (non-cash) expense included in G&A	911	8,310	17,337	17,905
Acquisition and divestiture costs included in G&A	1,771	1,133	28,693	1,829
Adjusted G&A	$ 11,983	$ 17,493	$ 65,813	$ 50,665
Average unit costs per Boe:				
General and administrative expense	$ 2.16	$ 5.68	$ 6.17	$ 4.70
Less:				
Stock-based compensation expense (non-cash) included in G&A	0.13	1.75	0.96	1.20
Acquisition and divestiture costs included in G&A	0.26	0.24	1.58	0.12
Adjusted G&A per Boe	$ 1.77	$ 3.69	$ 3.63	$ 3.38

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

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

To reduce the impact of fluctuations in oil, natural gas, and NGL prices on the Company's business and results of operations, 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. The derivative contracts may include fixed-for-floating 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-for-floating price swaps by agreeing to expand the notional quantity hedged or extend the notional quantity settlement period under a fixed-for floating price swap at the counterparty's election on a designated date.

Table of Contents

These hedging activities, which are governed by the terms of our Second Amended and Restated Credit Agreement and the SN UnSub Credit Agreement, as applicable, 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 lenders, or affiliates of lenders, to our Second Amended and Restated Credit Agreement or SN UnSub Credit Agreement are collateralized by the assets securing our Second Amended and Restated Credit Agreement or SN UnSub Credit Agreement, as applicable, and, therefore, do not currently require the posting of cash collateral. Our existing derivatives with non-lender counterparties, as designated under the Second Amended and Restated Credit Agreement and SN UnSub Credit Agreement, are unsecured and do not require the posting of cash collateral. It is never the Company's intention to enter into derivative contracts for speculative trading purposes. In connection with the closing of the Comanche Acquisition, we hedged a portion of projected future production attributable to the Comanche Assets, using hedge transactions that are consistent with our current hedging strategy. Please refer to Note 7, "Derivative Instruments" of Part 1, Item 1. Financial Statements for a description of all of the Company's derivatives covering anticipated future production as of September 30, 2017.

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

At September 30, 2017, the fair value of our commodity derivative contracts was a net asset of approximately $7.0 million. A 10% increase in the oil and natural gas index prices above the September 30, 2017 prices would result in a decrease in the fair value of our commodity derivative contracts of $97.2 million; conversely, a 10% decrease in the oil and natural gas index price would result in an increase of $98.9 million.

Interest Rate Risk

At the Company's election, borrowings under either the Second Amended and Restated Credit Agreement or SN UnSub Credit Agreement may be made on a variable ABR or a Eurodollar rate, plus an applicable margin determined based on the utilization of available borrowing capacity, as defined in the applicable credit agreement. As of September 30, 2017, there were no borrowings outstanding under the Second Amended and Restated Credit Agreement and $175.5 million in borrowings outstanding under the SN UnSub Credit Agreement.

Our 7.75% Notes bear a fixed interest rate of 7.75% with an expected maturity date of June 15, 2021, and we had $600 million outstanding as of September 30, 2017. Our 6.125% Notes bear a fixed interest rate of 6.125% with an expected maturity date of January 15, 2023, and we had $1.15 billion outstanding as of September 30, 2017.

Our Non-Recourse Subsidiary Term Loan bears a fixed interest rate of 4.59% with an expected maturity date of August 31, 2022, and we had $4.3 million outstanding as of September 30, 2017.

As of September 30, 2017, we did not have any interest rate derivative contracts in place. If we incur significant debt with a risk of fluctuating interest rates in the future under our Second Amended and Restated Credit Agreement or SN UnSub Credit Agreement, we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Rule 13a-15 promulgated pursuant to the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Based upon that evaluation, our principal executive officer and principal financial officer concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us in reports that we file or submit under the Exchange Act is appropriately recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that information required to be disclosed by us in the reports 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.

Changes in Internal Controls

There was no change in our internal control over financial reporting during the nine months ended September 30, 2017 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a description of our material pending legal proceedings, please refer to Note 16, “Commitments and Contingencies” of Part 1, Item 1. Financial Statements.

Item 1A. Risk Factors

Consider carefully the risk factors under the caption "Risk Factors" under Part I, Item 1A in our 2016 Annual Report, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2016 Annual Report; and in our other public filings, press releases, and public discussions with our management. Additional risks and uncertainties not currently known to us or that we currently deem immaterial may materially adversely affect our business, financial condition or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

EXHIBIT INDEX

2.1(a)	**	Purchase and Sale Agreement, dated as of August 17, 2017, by and between SN Cotulla Assets, LLC and Vitruvian Exploration IV, LLC.
3.1		Certificate of Amendment of Amended and Restated Certificate of Incorporation of Sanchez Energy Corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on May 28, 2013 (File No. 001-35372) and incorporated herein by reference).
3.2		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 (File No. 001-35372) and incorporated herein by reference).
3.3		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 (File No. 001-35372) and incorporated herein by reference).
3.4		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 (File No. 001-35372) and incorporated herein by reference).
10.1	(a)	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.
10.2	(a)	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.
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.

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.

Table of Contents

101.LAB (a) — XBRL Taxonomy Extension Labels Linkbase Document.

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

(a) Filed herewith.

(b) Furnished herewith.

**The exhibits and schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such omitted exhibits and schedules to the Securities and Exchange Commission upon request. Descriptions of such exhibits and schedules are set forth on page iv of the Purchase and Sale Agreement.

Table of Contents

SIGNATURES

Pursuant to the requirements 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 November 3, 2017.

SANCHEZ ENERGY CORPORATION

By: /s/ Kirsten A. Hink
Kirsten A. Hink
Senior Vice President and Chief Accounting Officer

(Duly Authorized Officer)

By: /s/ Howard J. Thill
Howard J. Thill
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)