Sanchez Midstream Partners LP
Form 10-Q
August 09, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2018

OR

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

For the transition period from to .

Commission File Number 001-33147

Sanchez Midstream Partners LP

(Exact name of registrant as specified in its charter)

Delaware	11-3742489
(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)

(Former name, former address and former fiscal year, if changed since last report)

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 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, or a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer	Non accelerated filer (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 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

Common units outstanding as of August 7, 2018: Approximately 15,972,808 units.

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Cautionary Note Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q contains "forward-looking statements" as defined by the United States Securities and Exchange Commission (the "SEC") that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include discussions about our business strategy; our acquisition strategy; our financing strategy; our ability to make, maintain and grow distributions; our future operating results; the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements; the ability of our partners to perform under our joint ventures and partnerships; our future capital expenditures; and our plans, objectives, expectations, forecasts, outlook and intentions.

All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Part I, Item 2. and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as "may," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "pred "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by the management of our general partner. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate.

Important factors that could cause our actual results to differ materially from the expectations reflected in the forward looking statements include, among others:

- our ability to successfully execute our business, acquisition and financing strategies;
- our ability to make, maintain and grow distributions;
- the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements;
- the ability of our partners to perform under our joint ventures and partnerships;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- our ability to utilize the services, personnel and other assets of the sole member of our general partner, SP Holdings, LLC ("Manager"), pursuant to existing services agreements;
- the credit worthiness and performance of our counterparties, including financial institutions, operating partners and other parties;
- the timing and extent of changes in prices for, and demand for, natural gas, natural gas liquids ("NGLs") and oil;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise;
- 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;
- competition in the oil and natural gas industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the extent to which our assets operated by others are operated successfully and economically;
- our ability to compete with other companies in the oil and natural gas industry;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and

use of water, laws and

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regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;

- 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 SEC.

Management cautions all readers that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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COMMONLY USED DEFINED TERMS

As used in this Quarterly Report on Form 10-Q, unless the context indicates or otherwise requires, the following terms have the following meanings:

- “Sanchez Midstream Partners,” “SNMP,” “the Partnership,” “we,” “us,” “our” or like terms refer collectively to Sanchez Midstream Partners LP, its consolidated subsidiaries and, where the context provides, the entities in which we have a 50% or more ownership interest.
- “Bbl” means a barrel of 42 U.S. gallons of oil.
- “Boe” means one barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.
- “Boe/d” means one Boe per day.
- “MBbl” means one thousand barrels of oil or other liquid hydrocarbons.
- “MBoe” means one thousand Boe.
- “Mcf” means one thousand cubic feet of natural gas.
- “MMBtu” means one million British thermal units.
- “MMcf/d” means one million cubic feet of natural gas per day.
- “NGLs” refers to the combination of ethane, propane, butane, natural gasolines and other components that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
- “our general partner” refers to Sanchez Midstream Partners GP LLC, our general partner.
- “Sanchez Energy” refers to Sanchez Energy Corporation (NYSE: SN) and its consolidated subsidiaries.
- “SOG” refers to Sanchez Oil & Gas Corporation, an entity that provides operational support to us.
- “SP Holdings” or “Manager” refers to SP Holdings, LLC, the sole member of our general partner.

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Operations

(In thousands, except unit data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Natural gas sales	$ 226	$ 2,252	$ 699	$ 5,031
Oil sales	1,584	8,109	5,046	19,459
Natural gas liquid sales	400	492	995	959
Gathering and transportation sales	1,661	14,176	3,349	25,387
Gathering and transportation lease revenues	13,168	—	25,486	—
Total revenues	17,039	25,029	35,575	50,836
Expenses				
Operating expenses				
Lease operating expenses	2,007	3,881	3,978	8,864
Transportation operating expenses	3,071	3,032	5,918	6,328
Cost of sales	—	40	—	77
Production taxes	287	353	609	826
General and administrative expenses	6,919	6,353	12,084	11,962
Unit-based compensation expense	1,347	780	2,785	1,320
Gain on sale of assets	(2,388)	—	(2,388)	—
Depreciation, depletion and amortization	6,545	8,937	13,173	21,118
Asset impairments	—	—	—	4,688
Accretion expense	123	240	249	498
Total operating expenses	17,911	23,616	36,408	55,681
Other (income) expense				
Interest expense, net	2,780	1,896	5,379	3,779
Earnings from equity investments	(3,111)	(1,042)	(7,383)	(1,524)
Other expense	1,254	—	1,524	—
Total other (income) expenses	923	854	(480)	2,255
Total expenses	18,834	24,470	35,928	57,936
Income (loss) before income taxes	(1,795)	559	(353)	(7,100)
Income tax expense	—	—	—	—
Net income (loss)	(1,795)	559	(353)	(7,100)
Less				
Preferred unit paid-in-kind distributions	(3,500)	—	(3,500)	(2,625)
Preferred unit distributions	(7,000)	(8,750)	(15,750)	(15,750)
Preferred unit amortization	(568)	(433)	(1,099)	(837)

Net loss attributable to common unitholders	$ (12,863)	$ (8,624)	$ (20,702)	$ (26,312)
Net loss per unit				
Common units - Basic and Diluted	$ (0.85)	$ (0.62)	$ (1.38)	$ (1.92)
Weighted Average Units Outstanding				
Common units - Basic and Diluted	15,199,779	13,939,993	14,997,058	13,671,557

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	June 30, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,484	$ 321
Accounts receivable	152	495
Accounts receivable - related entities	6,648	13,099
Prepaid expenses	2,587	2,670
Fair value of commodity derivative instruments	4	942
Total current assets	11,875	17,527
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	117,606	170,750
Gathering and transportation assets	185,615	184,969
Less: accumulated depreciation, depletion, amortization and impairment	(98,483)	(142,574)
Oil and natural gas properties and equipment, net	204,738	213,145
Other assets		
Intangible assets, net	165,436	172,166
Fair value of commodity derivative instruments	178	1,318
Equity investments	120,710	123,715
Other non-current assets	485	552
Total assets	$ 503,422	$ 528,423
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 4,405	$ 1,782
Accounts payable and accrued liabilities - related entities	7,065	10,353
Royalties payable	370	371
Fair value of commodity derivative instruments	2,049	756
Other liabilities	260	151
Total current liabilities	14,149	13,413
Other liabilities		
Asset retirement obligation	6,264	6,074
Long-term debt, net of debt issuance costs	183,040	187,808
Fair value of commodity derivative instruments	1,809	273
Other liabilities	7,666	6,251
Total other liabilities	198,779	200,406
Total liabilities	212,928	213,819
Commitments and contingencies (See Note 12)		
Mezzanine equity		
Class B preferred units, 31,000,887 units issued and outstanding as of June 30, 2018 and December 31, 2017	346,761	343,912
Partners' deficit		

Common units, 16,000,554 and 14,965,134 units issued and outstanding as of June 30, 2018 and December 31, 2017, respectively	(56,267)	(29,308)
Total partners' deficit	(56,267)	(29,308)
Total liabilities and partners' capital	$ 503,422	$ 528,423

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(unaudited)

	Six Months Ended June 30, 2018	2017
Cash flows from operating activities:		
Net loss	$ (353)	$ (7,100)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	6,443	14,294
Amortization of debt issuance costs	265	259
Asset impairments	—	4,688
Accretion expense	249	498
Distributions from equity investments	13,101	3,684
Equity earnings in affiliate	(7,383)	(1,524)
Gain from disposition of property and equipment	(2,388)	—
Net (gains) losses on commodity derivative contracts	5,653	(9,268)
Net cash settlements received (paid) on commodity derivative contracts	(706)	3,378
Unit-based compensation	2,785	2,019
Loss on earnout derivative	1,524	—
Amortization of intangible assets	6,730	6,824
Costs for plug and abandon activities	—	(45)
Changes in Operating Assets and Liabilities:		
Accounts receivable	185	(369)
Accounts receivable - related entities	6,541	(125)
Prepaid expenses	83	(567)
Other assets	43	(146)
Accounts payable and accrued liabilities	7,687	7,309
Accounts payable and accrued liabilities- related entities	(3,376)	(222)
Royalties payable	(1)	(171)
Net cash provided by operating activities	37,082	23,416
Cash flows from investing activities:		
Final settlement of oil and natural gas properties acquisition	—	1,468
Development of oil and natural gas properties	(205)	(210)
Proceeds from sale of assets	5,896	—
Construction of gathering and transportation assets	(1,700)	(15,240)
Purchases of and contributions to equity affiliates	(2,713)	(8,286)
Net cash provided by (used in) investing activities	1,278	(22,268)
Cash flows from financing activities:		
Payments for offering costs	(50)	(293)
Proceeds from issuance of debt	—	25,000
Repayment of debt	(5,000)	—
Issuance of common units	—	1,290

Distributions to common unitholders	(13,614)	(12,044)
Class B preferred unit cash distributions	(17,500)	(14,000)
Debt issuance costs	(33)	(27)
Net cash used in financing activities	(36,197)	(74)
Net increase in cash and cash equivalents	2,163	1,074
Cash and cash equivalents, beginning of period	321	957
Cash and cash equivalents, end of period	$ 2,484	$ 2,031
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 341	$ 8,601
Asset retirement obligation	$ 288	$ 195
Earnout derivative	$ —	$ 221
Cash paid during the period for interest	$ 4,788	$ 3,548

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Partners’ Capital for the Six Months Ended June 30, 2018

(In thousands, except unit data)

(Unaudited)

	Common Units		Total
	Units	Amount	Capital
Partners' Capital, December 31, 2016	13,447,749	$ 16,744	$ 16,744
Unit-based compensation programs	217,481	3,373	3,373
Issuance of common units, net of offering costs of $0.6 million	906,613	11,228	11,228
Cash distributions to common unit holders	—	(25,192)	(25,192)
Common units issued as Class B Preferred distributions	393,291	5,250	5,250
Distributions - Class B preferred units	—	(37,671)	(37,671)
Net loss	—	(3,040)	(3,040)
Partners' Deficit, December 31, 2017	14,965,134	(29,308)	(29,308)
Unit-based compensation programs	604,228	2,785	2,785
Issuance of common units, net of offering costs of $0.1 million	431,192	4,572	4,572
Cash distributions to common unit holders	—	(13,614)	(13,614)
Distributions - Class B preferred units	—	(20,349)	(20,349)
Net loss	—	(353)	(353)
Partners' Deficit, June 30, 2018	16,000,554	$ (56,267)	$ (56,267)

See accompanying notes to condensed consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BUSINESS

Organization

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. The Partnership has ownership stakes in oil and natural gas gathering systems, natural gas pipelines, and a natural gas processing facility, all located in the Western Eagle Ford in South Texas. We also own production assets in Texas and Louisiana. We have entered into a shared services agreement (the "Services Agreement") with SP Holdings, the sole member of our general partner, pursuant to which the Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services. On June 2, 2017, Sanchez Production Partners LP changed its name to Sanchez Midstream Partners LP. Manager owns the general partner of SNMP and all of SNMP's incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol "SNMP."

2. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Accounting policies used by us conform to accounting principles generally accepted in the United States of America ("U.S. GAAP"). These unaudited condensed consolidated financial statements include the accounts of us and our wholly owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation. We conduct our business activities as two operating segments: the production of oil and natural gas and the midstream business, which includes Western Catarina Midstream (defined in Note 10 "Intangible Assets"). Our management evaluates performance based on these two business segments.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the SEC. Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with U.S. GAAP, have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information presented not misleading. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary to fairly state the financial position, results of operations and cash flows with respect to the interim condensed consolidated financial statements have been included. The results of operations for the interim periods are not necessarily indicative of the results for the entire year.

These unaudited condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto of SNMP and its subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2017, which was filed with the SEC on March 12, 2018.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("FASB"), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our condensed consolidated financial statements upon adoption.

In June 2018, the FASB issued Accounting Standards Update ("ASU") 2018-07 "Compensation - Stock Compensation (Topic 718) - Improvements to Nonemployee Share-Based Payment Accounting," which expands the scope of Topic 718, Compensation – Stock Compensation, to include share-based payment transactions for acquiring goods and services from nonemployees. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2018. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

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. The Partnership adopted this ASU on January 1, 2018, using a prospective method; the clarified definition of a business will be applied by the Partnership to transactions executed subsequent to the effective date.

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 now effective for public business entities beginning after December 15, 2017. The Partnership does not currently have restricted cash.

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 is now effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The adoption of ASU 2016-16 did not have an impact on the Partnership’s unaudited condensed consolidated financial statements and related disclosures.

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. Additionally, in July 2018, the FASB issued ASU 2018-10, “Codification Improvements to Topic 842 (Leases),” which provides narrow amendments to clarify how to apply certain aspects of ASU 2016-02. The effective date in ASU 2018-10 is the same as that of ASU 2016-02. ASU 2016-02 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 those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee’s classification of a finance lease. The Partnership 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 Partnership is currently evaluating the impact of these rules on its consolidated financial statements and has started the assessment process by evaluating the population of leases under the revised definition. The Partnership is also in the process of implementing a lease accounting software to properly account for lease data upon adoption. The adoption of this standard will result in an increase in the assets and liabilities on the Partnership’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, May and December 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 Partnership adopted the standard effective January 1, 2018. For more information, see Note 3 “Revenue Recognition.”

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership’s financial position, results of operations and cash flows.

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 amounts reported in the consolidated financial statements and accompanying footnotes. These estimates and the underlying assumptions affect the amounts of assets and liabilities reported, disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include estimates of our reserves of natural gas, NGLs and oil; future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of derivatives; and fair values of assets and liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best judgment using the data available. Management evaluates its estimates and assumptions on an on-going basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from the estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

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3. REVENUE RECOGNITION

Adoption of Topic 606

Effective January 1, 2018, the Partnership adopted the new Accounting Standards Codification (“ASC”) 606, Revenue from Contracts with Customers, and all the related amendments (collectively referred to as “Topic 606”) to all open contracts using the modified retrospective approach. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

For contracts that have a contract term of one year or less, we elected to utilize the practical expedient permitted under the rules of adoption whereby a Company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Adoption of this guidance resulted in financial statement presentation changes whereby revenue from the Gathering Agreement (defined in Note 13 “Related Party Transactions”) and revenue from the Seco Pipeline Transportation Agreement (defined in Note 13 “Related Party Transactions”) are shown as separate line items within our condensed consolidated statement of operations. There was no cumulative adjustment to retained earnings or any other changes to our January 1, 2018 condensed consolidated balance sheet.

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Topic 606. The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract’s transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

Disaggregation of Revenue

We disaggregate revenue based on type of revenue and product type. In selecting the disaggregation categories, we considered a number of factors, including disclosures presented outside the financial statements, such as in our earnings release and investor presentations, information reviewed internally for evaluating performance, and other factors used by the Partnership or the users of its financial statements to evaluate performance or allocate resources. We have concluded that disaggregating revenue by type of revenue and product type appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

Midstream Segment

The Seco Pipeline Transportation Agreement is our only contract that we account for under Topic 606. The Catarina Midstream Gathering Agreement was classified as an operating lease at inception and is accounted for under ASC 840, Leases, and is reported as Gathering and transportation lease revenue in our condensed consolidated statement of operations. Both of these contracts are further discussed in Note 13 “Related Party Transactions.”

We account for income from our unconsolidated equity method investments as earnings from equity investments in our condensed consolidated statements of operations. Earnings from these equity method investments are further discussed in Note 11 “Investments.”

Production Segment

Our oil, natural gas, and NGL revenue is marketed and sold on our behalf by the respective asset operators. We are not party to the contracts with the third-party customers. However, we are party to joint operating agreements, which we account for under ASC 808, and revenue for these arrangements is recognized based on the information provided to us by the operators.

We additionally recognize and present changes in the fair value of our commodity derivative instruments within natural gas sales and oil sales in the condensed consolidated statements of operations. As this income is accounted for under ASC 815, Derivatives and Hedging, it is not subject to Topic 606.

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We recognized revenue of $17.0 million for three months ended June 30, 2018. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Three Months Ended June 30, 2018		
	Production	Midstream	Total
Revenues:			
Natural gas sales	$ 226	$ —	$ 226
Oil sales	1,584	—	1,584
Natural gas liquid sales	400	—	400
Gathering and transportation sales	—	1,661	1,661
Gathering and transportation lease revenues	—	13,168	13,168
Total revenues	$ 2,210	$ 14,829	$ 17,039

We recognized revenue of $35.6 million for six months ended June 30, 2018. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Six Months Ended June 30, 2018		
	Production	Midstream	Total
Revenues:			
Natural gas sales	$ 699	$ —	$ 699
Oil sales	5,046	—	5,046
Natural gas liquid sales	995	—	995
Gathering and transportation sales	—	3,349	3,349
Gathering and transportation lease revenues	—	25,486	25,486
Total revenues	$ 6,740	$ 28,835	$ 35,575

Performance Obligations

Under the Seco Pipeline Transportation Agreement, we agreed to provide transportation services of certain quantities of natural gas from the receipt point to the delivery point. Each MMBtu of natural gas transported is distinct and the transportation services performed on each distinct molecule of product is substantially the same in nature. As such, we applied the series guidance and treat these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. The Seco Pipeline Transportation Agreement requires payment within 30 days following the calendar month of delivery.

The Seco Pipeline Transportation Agreement contains variable consideration in the form of volume variability. As the distinct goods or services (rather than the series) are considered for the purpose of allocating variable consideration, we have taken the optional exception under ASC 606-10-50-14A(b) which is available only for wholly unsatisfied performance obligations for which the criteria in ASC 606-10-32-40 have been met. Under this exception, neither estimation of variable consideration nor disclosure of the transaction price allocated to the remaining performance obligations is required. Revenue is alternatively recognized in the period that control is transferred to the customer and the respective variable component of the total transaction price is resolved.

For forms of variable consideration that are not associated with a specific volume (such as late payment fees) and thus do not meet allocation exception, estimation is required. These fees, however, are immaterial to our consolidated financial statements and have a low probability of occurrence. As significant reversals of revenue due to this variability are not probable, no estimation is required.

Contract Balances

Under our sales contracts, we invoice customers after our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under Topic 606. At January 1, 2018 and June 30, 2018, our receivables from contracts with customers were $1.1 million and $0.6 million, respectively, and are presented within Accounts receivable – related entities on the condensed consolidated balance sheets.

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Reconciliation of Statement of Operations

The impact of adopting Topic 606 on our condensed consolidated statement of operations is as follows (in thousands):

	Three Months Ended June 30, 2018		
	As reported	Balances without Adoption Topic 606	Effect of change Higher/(Lower)
Statement of Operations			
Gathering and transportation sales	$ 1,661	$ 14,829	$ (13,168)
Gathering and transportation lease revenues	13,168	—	13,168
Net earnings	$ 14,829	$ 14,829	$ —

	Six Months Ended June 30, 2018		
	As reported	Balances without Adoption Topic 606	Effect of change Higher/(Lower)
Statement of Operations			
Gathering and transportation sales	$ 3,349	$ 28,835	$ (25,486)
Gathering and transportation lease revenues	25,486	—	25,486
Net earnings	$ 28,835	$ 28,835	$ —

We expect the impact of the adoption of Topic 606 to be immaterial to our net income (loss) on an ongoing basis.

4. ACQUISITIONS AND DIVESTITURES

Briggs Divestiture

In April 2018, we entered into a purchase and sale agreement to sell specified wellbores and other associated assets and interests in La Salle County Texas (the “Briggs Assets”) for a base purchase price of approximately $4.5 million which, after giving effect to preliminary purchase price adjustments, was reduced to approximately $4.0 million (the “Briggs Divestiture”), and remains subject to final post-closing adjustments. In addition, other than a limited amount of retained obligations, the buyer agreed to assume all obligations relating to the Briggs Assets, including all plugging and abandonment costs, that may arise on or after March 1, 2018. The Briggs Divestiture closed April 30, 2018, and we recorded a gain of approximately $1.6 million on the sale during the second quarter 2018.

Cola Divestiture

In April 2018, we entered into a purchase and sale agreement to sell certain non-operated production assets located in Oklahoma for cash consideration of approximately $1.0 million. The Oklahoma Divestiture closed on April 30, 2018, and we recorded a gain of approximately $1.1 million on the sale during the second quarter 2018.

Texas Production Divestiture

In October 2017, we entered into a purchase and sale agreement to sell specified oil and gas wells, leases and other associated assets and interests located in Texas (the “Texas Production Assets”) for cash consideration of approximately $6.3 million (the “Texas Production Divestiture”). In addition, the buyer agreed to assume all obligations relating to the assets, including all plugging and abandonment costs relating to the Texas Production Assets, that may arise on or after October 1, 2017. The Texas Production Divestiture closed November 13, 2017, and we recorded a gain of approximately $1.4 million on the sale during the fourth quarter of 2017.

Non-Operated Production Divestiture

In July 2017, we entered into an agreement to assign certain non-operated production assets located in Oklahoma, as well as our equity interests in the entities that owned such assets, in exchange for agreeing upon the apportionment of certain shared litigation costs. The assignment became effective as of July 14, 2017.

Oklahoma Production Divestiture

In May 2017, we entered into a purchase and sale agreement to sell all of the Partnership’s equity interests in the entities that owned our remaining operated Oklahoma production assets for cash consideration of $5.5 million, and assumption by the buyer of all

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obligations relating to such assets arising after the closing date and all plugging and abandonment costs relating to the assets arising prior to the closing date (the "Oklahoma Production Divestiture"). The Oklahoma Production Divestiture closed July 17, 2017, and we recorded a gain of $2.4 million on the sale during the third quarter of 2017.

5. FAIR VALUE MEASUREMENTS

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. Substantially all of these inputs are observable in the marketplace throughout the term of the 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).

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.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2018 (in thousands):

	Fair Value Measurements at June 30, 2018			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative liability	$ —	$ (3,676)	$ —	$ (3,676)
Midstream derivative instrument				
Earnout derivative liability	—	—	(7,926)	(7,926)
Total	$ —	$ (3,676)	$ (7,926)	$ (11,602)

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2017 (in thousands):

	Fair Value Measurements at December 31, 2017			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value

Commodity derivative instrument				
Derivative assets	$ —	$ 1,231	$ —	$ 1,231
Midstream derivative instrument				
Earnout derivative liability	—	—	(6,402)	(6,402)
Total	$ —	$ 1,231	$ (6,402)	$ (5,171)

As of June 30, 2018 and December 31, 2017, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of Topic 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the

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market and therefore represent Level 3 inputs under the fair value hierarchy. We periodically review oil and natural gas properties for impairment when facts and circumstances indicate that their carrying values may not be recoverable.

A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 9, "Asset Retirement Obligation."

The following table summarizes the non-recurring fair value measurements of our assets as of June 30, 2018 (in thousands):

	Fair Value Measurements at June 30, 2018		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment	$ —	$ —	$ —
Total net assets	$ —	$ —	$ —

The following table summarizes the non-recurring fair value measurements of our assets as of December 31, 2017 (in thousands):

	Fair Value Measurements at December 31, 2017		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment(a)	$ —	$ —	$ 7,277
Total net assets	$ —	$ —	$ 7,277

(a) During the year ended December 31, 2017, we recorded a non-cash impairment charge of $4.7 million to impair our producing oil and natural gas properties. The carrying values of the impaired properties were reduced to a fair value of $7.3 million, estimated using inputs characteristic of a Level 3 fair value measurement.

The fair values of oil and natural gas properties were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Credit Agreement – We believe that the carrying value of long-term debt for our Credit Agreement (defined in Note 7 "Long-Term Debt") approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our Credit Agreement is discussed further in Note 7, "Long-Term Debt."

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate derivatives as of June 30, 2018. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

Earnout Derivative – As part of the Carnero Gathering Transaction (defined in Note 11 "Investments"), we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. The earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. We have therefore classified the fair value measurements of our earnout derivative as Level 3 inputs and currently present it within the other liabilities lines on the condensed consolidated balance sheets.

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The following table sets forth a reconciliation of changes in the fair value of the Partnership's earnout derivative classified as Level 3 in the fair value hierarchy (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Beginning balance	$ (6,402)	$ (4,270)
Initial fair value of earnout derivative	—	221
Loss on earnout derivative	(1,524)	(2,353)
Ending balance	$ (7,926)	$ (6,402)
Loss included in earnings related to derivatives still held as of June 30, 2018 and December 31, 2017, respectively	$ (1,524)	$ (2,353)

6. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under Topic 815, “Derivatives and Hedging,” all derivative 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. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives’ fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have not elected to designate any of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included in natural gas sales and oil sales in the condensed consolidated statements of operations.

As of June 30, 2018, we had the following derivative contracts in place for the periods indicated, all of which are accounted for as mark-to-market activities:

Fixed Price Basis Swaps – West Texas Intermediate (WTI)

	Three Months Ended (volume in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2018	—	$ —	—	$ —	62,840	$ 59.78	59,704	$ 59.84	122,544	$ 59.81
2019	62,528	$ 60.41	59,552	$ 60.44	57,024	$ 60.48	54,824	$ 60.52	233,928	$ 60.46
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50

557,056

Fixed Price Swaps—NYMEX (Henry Hub)

	Three Months Ended (volume in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2018	—	$ —	—	$ —	121,600	$ 3.00	117,040	$ 3.00	238,640	$ 3.00
2019	119,832	$ 2.85	115,784	$ 2.85	112,032	$ 2.85	108,552	$ 2.85	456,200	$ 2.85
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85
									1,097,288	

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The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the six months ended June 30, 2018 and the year ended December 31, 2017 (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Beginning fair value of commodity derivatives	$ 1,231	$ 6,436
Net gains (losses) on crude oil derivatives	(5,657)	3,284
Net gains on natural gas derivatives	4	663
Net settlements paid (received) on derivative contracts:		
Oil	771	(6,422)
Natural gas	(25)	(2,730)
Ending fair value of commodity derivatives	$ (3,676)	$ 1,231

The effect of derivative instruments on our condensed consolidated statements of operations was as follows (in thousands):

		Amount of Gain (Loss) in Income			
	Location of Gain(Loss)	Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Type	in Income	2018	2017	2018	2017
Commodity – Mark-to-Market	Oil sales	$ (3,717)	$ 3,048	$ (5,657)	$ 8,543
Commodity – Mark-to-Market	Natural gas sales	2	165	4	725
		$ (3,715)	$ 3,213	$ (5,653)	$ 9,268

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with four counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments. In August 2017, we repositioned certain of our crude oil and natural gas hedges in anticipation of the sale of the Texas Production Assets and, in the process, received $3.6 million in net cash from the counterparties on those hedges. As of June 30, 2018 and December 31, 2017, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Earnout Derivative

Refer to Note 5 "Fair Value Measurements".

7. LONG-TERM DEBT

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (the "Credit Agreement"). The Credit Agreement provides a maximum commitment of $500.0 million and has a maturity date of March 31, 2020. Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that we own, as well as various security and pledge agreements among the Partnership, certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of $15.0 million which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was $200.0 million. The borrowing base for the credit available for the upstream oil and gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is generally equal to the rolling four quarter Adjusted EBITDA of our midstream operations, together with the amount of distributions received from Carnero JV (defined in Note 11 “Investments”) multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders. As of June 30, 2018, the borrowing base under the Credit Agreement was $310.0 million, with an elected commitment amount of $200.0 million, and we had $184.0 million of debt outstanding under the facility, leaving us with $16.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of June 30, 2018. Our Credit Agreement matures on March 31, 2020.

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At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank rate ("LIBOR") plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) a domestic bank rate ("ABR") plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus (iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

- current assets to current liabilities of at least 1.0 to 1.0 at all times;
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the adjusted EBITDA of our midstream operations equals or exceeds one-third of total Adjusted EBITDA or 4.0 to 1.0 if the adjusted EBITDA of our midstream operations is less than one-third of total adjusted EBITDA; and
- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed to be made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At June 30, 2018, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance for any violation of a financial covenant from the lenders, but there is no assurance that such waivers would be granted.

Debt Issuance Costs

As of June 30, 2018 and December 31, 2017, our unamortized debt issuance costs were $1.0 million and $1.2 million, respectively. These costs are amortized to interest expense in our condensed consolidated statements of operations over the life of our Credit Agreement. Amortization of debt issuance costs recorded during each of the three months ended June 30, 2018 and 2017 were $0.1 million. Amortization of debt issuance costs recorded during each of the six months ended June 30, 2018 and 2017 were $0.3 million.

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8. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

Gathering and transportation assets consisted of the following (in thousands):

	June 30, 2018	December 31, 2017
Gathering and transportation assets		
Midstream assets	$ 185,615	$ 184,969
Less: Accumulated depreciation and amortization	(30,698)	(26,870)
Total gathering and transportation assets	$ 154,917	$ 158,099

Oil and natural gas properties consisted of the following (in thousands):

	June 30, 2018	December 31, 2017
Oil and natural gas properties and related equipment		
Proved property	$ 117,606	$ 170,750
Less: Accumulated depreciation, depletion, amortization and impairments	(67,785)	(115,704)
Oil and natural gas properties and equipment, net	$ 49,821	$ 55,046

Oil and Natural Gas Properties. We follow the successful efforts method of accounting for our oil and natural gas production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties.

Depreciation, Depletion and Amortization. Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves.

All other properties, including the gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, and up to 36 years for gathering facilities.

Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 1,251	$ 2,877	$ 2,614	$ 6,111
Depreciation and amortization of gathering and transportation related assets	1,929	2,648	3,829	8,183
Amortization of intangible assets	3,365	3,412	6,730	6,824
Total Depreciation, depletion and amortization	6,545	8,937	13,173	21,118
Asset impairments	—	—	—	4,688
Total	$ 6,545	$ 8,937	$ 13,173	$ 25,806

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets. Oil and natural gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates are based upon reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Other significant inputs, besides reserves, used to determine the fair values of proved properties include estimates of: (i) future operating and development costs; (ii) future commodity prices; and (iii) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Cash flow estimates for impairment testing exclude derivative instruments.

The recoverability of gathering and transportation assets is evaluated when facts or circumstances indicate that their carrying value may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future

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undiscounted cash flows, we recognize an impairment equal to the excess of net book value over fair value. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our gathering and transportation assets and the recognition of additional impairments. Upon disposition or retirement of gathering and transportation assets, any gain or loss is recorded to operations.

For the three months and six months ended June 30, 2018, we recorded no impairment charges. For the three months ended June 30, 2017, we recorded no impairment charges. For the six months ended June 30, 2017 we recorded non-cash charges of $4.7 million to impair certain of our producing oil and natural gas properties in Texas.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation (“ARO”) in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost (“ARC”) is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities or gathering and transportation assets. Subsequently, the ARC is depreciated using the units-of-production method for production assets and the straight-line method for midstream assets. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance.

The following table is a reconciliation of changes in ARO (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Asset retirement obligation, beginning balance	$ 6,074	$ 13,579
Liabilities added from escalating working interests	288	198
Sales	(347)	(8,416)
Settlements	—	(60)
Accretion expense	249	773
Asset retirement obligation, ending balance	$ 6,264	$ 6,074

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. During the six months ended June 30, 2018 and the year ended December 31, 2017, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs. During the six months ended June 30, 2018, obligations were sold as part of the Briggs Divestiture and during the year ended December 31, 2017, obligations were sold as part of the Oklahoma Production Divestiture and Texas Production Divestiture.

10. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes $165.4 million related to the Gathering Agreement (defined in Note 13 “Related Party Transactions”) with Sanchez Energy that was entered into as part of the acquisition of the Western Catarina gathering system (“Western Catarina Midstream”). Pursuant to the 15-year agreement, Sanchez Energy tenders all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15-year life of the agreement.

Amortization expense for the six months ended June 30, 2018 and 2017 was $6.7 million and $6.8 million, respectively. These costs are amortized to depreciation, depletion, and amortization expense in our condensed consolidated statement of operations. The following table is a reconciliation of changes in intangible assets (in thousands):

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	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Beginning balance	$ 172,166	$ 185,766
Disposals	—	(32)
Amortization	(6,730)	(13,568)
Ending balance	$ 165,436	$ 172,166

11. INVESTMENTS

In July 2016, we completed a transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Gathering, LLC (“Carnero Gathering”), a joint venture that was 50% owned and operated by Targa Resources Corp. (NYSE: TRGP) (“Targa”), for an initial payment of approximately $37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million as of the acquisition date (the “Carnero Gathering Transaction”). The fair value of the intangible asset for the contractual customer relationship related to Carnero Gathering was valued at approximately $13.0 million. This amount is being amortized over a contract term of 15 years and decreases “Earnings from equity investments” line within the condensed consolidated statements of operations.

As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. See Note 5 “Fair Value Measurements” for further discussion of the earnout derivative.

In November 2016, we completed a transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Processing, LLC (“Carnero Processing”), a joint venture that was 50% owned and operated by Targa, for aggregate cash consideration of approximately $55.5 million and the assumption of remaining capital contribution commitments to Carnero Processing, estimated at approximately $24.5 million as of the date of acquisition (the “Carnero Processing Transaction”).

In May 2018, we executed a series of agreements with Targa pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering and Carnero Processing (the “Carnero JV Transaction”) to form an expanded 50 / 50 joint venture in South Texas, Carnero G&P, LLC (“Carnero JV”), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant (“Silver Oak II”), located in Bee County Texas, to Carnero JV, which expands the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the Carnero Gathering Line to Carnero JV resulting in the joint venture owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) the joint venture received a new dedication of over 315,000 Comanche acres in the Western Eagle Ford, operated by Sanchez Energy. As a result of the Carnero JV Transaction we now record our share of earnings and losses from Carnero JV using the Hypothetical Liquidation at Book Value (“HLBV”) method of accounting, beginning with the three months ended June 30, 2018. The HLBV is a balance-sheet approach that calculates the amount we would have received if Carnero JV were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our condensed consolidated statements of operations. In the event of liquidation of Carnero JV, available proceeds are first distributed to any priority return and unpaid capital associated with Silver Oak II, and then to members in accordance with their capital accounts.

As of June 30, 2018, the Partnership had paid approximately $123.7 million for its investment in Carnero JV related to the initial payments and contributed capital. The Partnership has accounted for this investment using the equity method. Targa is the operator of the joint venture and has significant influence with respect to the normal day-to-day construction and operating decisions. We have included the investment balance in the “Equity investments” caption on our condensed consolidated balance sheet. For the three months ended June 30, 2018, the Partnership recorded earnings of approximately $3.4 million in equity investments from Carnero JV, which was offset by approximately $0.3 million related to the amortization of the contractual customer intangible asset. For the six months ended June 30, 2018, the Partnership recorded earnings of approximately $8.0 million in equity investments from Carnero JV, which was offset by approximately $0.6 million related to the amortization of the contractual customer intangible asset. We have included these equity method earnings in the “Earnings from equity investments” line within the condensed consolidated statements of operations. Cash distributions of approximately $13.1 million were received during the six months ended June 30, 2018.

Summarized financial information of unconsolidated entities is as follows (in thousands):

	Six Months Ended June 30,	
	2018	2017
Sales	$ 179,798	$ 15,222
Total expenses	163,091	10,960
Net income	$ 16,707	$ 4,262

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	June 30, 2018	December 31, 2017
Current assets	$ 48,079	$ 38,344
Noncurrent assets	299,187	193,748
Current liabilities	38,575	24,710

12. COMMITMENTS AND CONTINGENCIES

As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. This earnout has an approximate value of $7.9 million and was recorded on the balance sheet as other liabilities as of June 30, 2018. Refer to Note 13 "Related Party Transactions" for further discussion of the earnings and payments made during 2018 related to the earnout.

13. RELATED PARTY TRANSACTIONS

Sanchez-Related Agreements

We are controlled by our general partner. The sole member of our general partner is Manager, which has no officers. In May 2014, we entered into the Services Agreement with Manager pursuant to which Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services and professionals. In connection with providing services under the Services Agreement, Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, is paid in cash unless Manager elects for such fee to be paid in our equity. Manager or the Partnership may terminate the Services Agreement at any time with at least 180 days' notice. Unless terminated pursuant to the immediately preceding sentence, the Services Agreement has an initial ten-year term and will be automatically renewed for an additional ten years unless either Manager or the Partnership provides notice of termination to the other at least 180 days' prior to the expiration of the initial ten-year term. During the three and six months ended June 30, 2018, we incurred costs of approximately $2.6 million and $4.9 million, respectively, to Manager under the Services Agreement.

Manager utilizes SOG to provide the services under the Services Agreement. In May 2014, we entered into a Contract Operating Agreement with SOG pursuant to which SOG either provides services to operate, develop and produce our oil and natural gas properties or engages a third-party operator to do so. We also have entered into the Geophysical Seismic Data Use License Agreement with SOG pursuant to which SOG provides us a non-exclusive, royalty-free license to use seismic, geophysical and geological information relating to our oil and natural gas properties that is proprietary to SOG and not restricted by agreements that SOG has with landowners or seismic data vendors.

SOG, headquartered in Houston, Texas, is a private full-service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. Antonio R. Sanchez, III (the Chairman of the board of directors of our general partner), Patricio D. Sanchez (the President and Chief Operating Officer of our general partner and a member on the board of directors of our general partner), and Eduardo A. Sanchez (a member on the board of directors of our general partner), along with their immediate family members, Ana Lee Sanchez Jacobs and Antonio R. Sanchez, Jr., collectively, either directly or indirectly, own a majority of the equity interests of SOG. In addition, Antonio R. Sanchez, Jr. is a member of the board of directors of SOG, and such other individuals, as well as Ana Lee Sanchez Jacobs, are officers of SOG.

Sanchez-Related Transactions

We have entered into several transactions with Sanchez Energy since January 1, 2016. Antonio R. Sanchez, Jr. is a director and Executive Chairman of the Board of Sanchez Energy, and Antonio R. Sanchez, III is a director and Chief Executive Officer of Sanchez Energy. In addition, Eduardo A. Sanchez is the former President of Sanchez Energy and Patricio D. Sanchez is an Executive Vice President of Sanchez Energy. The employees of SOG, including Kirsten A. Hink, our Chief Accounting Officer, provide common services to both us and Sanchez Energy.

In conjunction with the acquisition of Western Catarina Midstream, we entered into a 15-year gas gathering agreement with Sanchez Energy pursuant to which Sanchez Energy agreed to tender all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres in the Western Catarina area of the Eagle Ford Shale in South Texas for processing and transportation through Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the "Gathering Agreement"). During the first five years of the term of the Gathering Agreement, Sanchez Energy is required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. Sanchez Energy is required to pay gathering and processing fees of $0.96 per barrel for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through Western Catarina Midstream, in each case, subject to an annual escalation for a positive increase in the consumer price index. For the six months ended June 30, 2018 and 2017, Sanchez Energy paid us approximately $30.5 million and $24.1 million, respectively, pursuant to the terms of the Gathering Agreement. Under Topic 606, this amount is being presented under gathering and transportation lease revenue on the condensed consolidated statements of operations. On June 30, 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by a subsidiary of Sanchez Energy based on water that is delivered through the gathering system through March 31, 2018. The parties have agreed to continue the incremental infrastructure fee on a month-to-month basis.

In July 2016, we completed the Carnero Gathering Transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Gathering, a joint venture that was 50% owned and operated by Targa for an initial payment of approximately $37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million as of the acquisition date. As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. For the three and six months ended June 30, 2018 and 2017, natural gas received did not exceed the threshold. However, we made an earnout payment to Sanchez Energy for $0.1 million in the first quarter of 2018 related to the year ended December 31, 2017. The earnout is being accounted for as a derivative in the condensed consolidated financial statements. Refer to Note 5 "Fair Value Measurements" for additional discussion.

In November 2016, we completed the Carnero Processing Transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Processing, a joint venture that was 50% owned and operated by Targa, for aggregate cash consideration of approximately $55.5 million and the assumption of remaining capital contribution commitments to Carnero Processing, estimated at approximately $24.5 million as of the date of acquisition. Also in November 2016, the Partnership consummated a Purchase and Sale Agreement with SN Cotulla Assets, LLC and SN Palmetto, LLC, each a wholly-owned subsidiary of Sanchez Energy, to purchase working interests in 23 producing Eagle Ford Shale wellbores located in Dimmit and Zavala counties in South Texas as well as escalating working interests in an additional 11 producing wellbores in the Palmetto Field in Gonzales, Texas for approximately $24.2 million. In October 2016, we entered into an agreement with Sanchez Energy providing us an option to acquire a ground lease, which the parties mutually terminated in September 2017.

In November 2016, in conjunction with our public offering of common units, the Partnership entered into a Common Unit Purchase Agreement with SN UR Holdings, LLC (the "Purchaser"), a wholly owned subsidiary of Sanchez Energy, whereby we issued to the Purchaser 2,272,727 common units for proceeds of approximately $25.0 million.

In September 2017, we entered into an agreement with a subsidiary of Sanchez Energy to transport certain quantities of the subsidiary's natural gas on a firm basis through a 30 mile natural gas pipeline with 400 MMcf/d capacity designed and used to transport dry gas from the Raptor Gas Processing Facility to multiple markets in South Texas, that is 100% owned and operated by the Partnership (the "Seco Pipeline"), for $0.22 per MMBtu delivered on or after September 1, 2017 (the "Seco Pipeline Transportation Agreement"). The Seco Pipeline Transportation Agreement continues month-to-month until terminated by either party. For the six months ended June 30, 2018, SN Catarina paid us approximately $3.8 million pursuant to the terms of that agreement.

In May 2018, we executed the Carnero JV Transaction with Targa. In connection with the Carnero JV Transaction, effective April 1, 2018, a subsidiary of Sanchez Energy and Carnero JV entered into a Firm Gas Gathering, Processing and Purchase Agreement (the “Carnero Gas Gathering Agreement”) and other related documentation providing for certain gas gathering, treating and processing services in exchange for an approximately 315,000 gross acreage dedication from the subsidiary of Sanchez Energy and its working interest partners. Additionally, effective April 1, 2018, and in connection with the Carnero JV Transaction, another subsidiary of Sanchez Energy and an affiliate of Targa also amended their Firm Gas Gathering Agreement (the “Amended Gathering Agreement”) and Firm Gas Processing Agreement (the “Amended Processing Agreement”) which were subsequently assigned by the Targa counterparty to Carnero JV.

As of June 30, 2018 and December 31, 2017, the Partnership had a net receivable from related parties of approximately $6.6 million, and $13.1 million, respectively, which are included in “Accounts receivable – related entities” on the consolidated balance sheets. As of June 30, 2018 and December 31, 2017, the Partnership also had a net payable to related parties of approximately $7.1 million, and $10.4 million, respectively. The net receivable/payable as of June 30, 2018 and December 31, 2017 consist primarily of revenues receivable from oil and natural gas production and transportation, offset by costs associated with that production and transportation and obligations for general and administrative costs.

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Sanchez Energy 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 where it has assembled approximately 485,000 gross leasehold acres (283,000 net acres). The Chairman of the board of directors of our general partner, Antonio R. Sanchez, III, is Sanchez Energy's Chief Executive Officer and a member of its board of directors. A member of the board of directors of our general partner, Eduardo A. Sanchez, is the former President of Sanchez Energy. The President and Chief Operating Officer of our general partner, Patricio D. Sanchez, who is also a member of the board of directors of our general partner, is an Executive Vice President of Sanchez Energy. Antonio R. Sanchez, Jr., the father of Antonio R. Sanchez, III, Eduardo A. Sanchez, and Patricio D. Sanchez, is the Executive Chairman of the board of directors of Sanchez Energy. Antonio R. Sanchez, Jr., Antonio R. Sanchez, III and Patricio D. Sanchez beneficially own approximately 7.1%, 3.5%, and 1.5%, respectively, of Sanchez Energy's shares of common stock outstanding as of June 30, 2018. Sanchez Energy indirectly, through one of its wholly owned subsidiaries, beneficially owned approximately 14.2% of the outstanding common units of SNMP as of June 30, 2018.

14. UNIT-BASED COMPENSATION

The Sanchez Midstream Partners LP Long-Term Incentive Plan (the "LTIP") allows for grants of restricted common units. Restricted common unit activity under the LTIP during the period is presented in the following table:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2017	283,138	$ 14.64
Granted	622,534	11.94
Vested	(236,495)	13.62
Returned/Cancelled	(18,306)	12.50
Outstanding at June 30, 2018	650,871	$ 12.49

In April 2018, the Partnership issued 63,630 restricted common units pursuant to the LTIP to certain directors of the Partnership's general partner that vested immediately on the date of grant. In April 2018, the Partnership issued 244,813 and 314,091 restricted common units pursuant to the LTIP to executives that vest on the first anniversary of the date of grant and to non-executive employees that vest over three years from the date of grant, respectively.

In March 2017, the Partnership issued 171,231 restricted common units pursuant to the LTIP to executives of the Partnership's general partner that vested on the first anniversary of the date of grant in March 2018. The unit-based compensation expense for the award was based on the fair value on the day before the date of grant.

As of June 30, 2018, 1,152,965 common units remained available for future issuance to participants under the LTIP.

15. DISTRIBUTIONS TO UNITHOLDERS

The table below reflects the payment of cash distributions on common units related to the six months ended June 30, 2018 and the year ended December 31, 2017.

Three months ended	Distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2017	$ 0.4375	May 10, 2017	May 22, 2017	May 31, 2017
June 30, 2017	$ 0.4441	August 9, 2017	August 22, 2017	August 31, 2017
September 30, 2017	$ 0.4508	November 7, 2017	November 20, 2017	November 30, 2017
December 31, 2017	$ 0.4508	February 8, 2018	February 20, 2018	February 28, 2018
March 31, 2018	$ 0.4508	May 8, 2018	May 22, 2018	May 31, 2018
June 30, 2018	$ 0.4508	August 8, 2018	August 21, 2018	August 31, 2018

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The table below reflects the payment of distributions on Class B Preferred Units (defined below) related to the six months ended June 30, 2018, and the year ended December 31, 2017.

Three months ended	Cash distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2017 (a)	$ 0.2258	May 10, 2017	May 22, 2017	May 31, 2017
June 30, 2017	$ 0.28225	August 9, 2017	August 22, 2017	August 31, 2017
September 30, 2017	$ 0.28225	November 7, 2017	November 20, 2017	November 30, 2017
December 31, 2017	$ 0.28225	February 8, 2018	February 20, 2018	February 28, 2018
March 31, 2018	$ 0.28225	May 8, 2018	May 22, 2018	May 31, 2018
June 30, 2018 (b)	$ 0.2258	August 8, 2018	August 21, 2018	August 31, 2018

(a) The Partnership elected to pay the first quarter 2017 distribution on the Class B Preferred Units in part cash and, with consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B Preferred Units). Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B preferred unit and an aggregate distribution of 184,697 common units, each payable on May 31, 2017 to holders of record on May 22, 2017.

(b) The Partnership elected to pay the second quarter 2018 distribution on the Class B Preferred Units in part cash and part in Class B Preferred Units. Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B Preferred Unit and an aggregate distribution of 310,009 Class B Preferred PIK Units, each payable on August 31, 2018 to holders of record on August 21, 2018.

16. PARTNERS' CAPITAL

Outstanding Units

As of June 30, 2018, we had 31,000,887 Class B Preferred Units outstanding, and 16,000,554 common units outstanding, which included 650,871 unvested restricted common units issued under the LTIP.

Common Unit Issuances

The following table shows the common units issued by the Partnership in 2017 and 2018 to SP Holdings in connection with providing services under the Services Agreement:

Three months ended	Common units	Date of issuance
September 30, 2016	170,750	March 6, 2017
December 31, 2016	154,737	March 6, 2017
March 31, 2017	139,110	June 30, 2017
June 30, 2017	170,497	August 31, 2017
September 30, 2017	186,942	November 30, 2017
December 31, 2017	210,978	March 15, 2018
March 31, 2018	220,214	May 31, 2018

The Partnership elected to pay the first quarter 2017 distribution on the Class B Preferred Units in part cash and, with the consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B Preferred Units). Accordingly, the Partnership issued 184,697 common units on May 22, 2017, to the Class B preferred unitholder.

In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately $1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015 as updated by that certain prospectus supplement filed with the SEC on April 6, 2017 (the “Shelf Registration Statement”). The Shelf Registration Statement allows the Partnership to sell up to $50.0 million of common units at-the-market to fund general limited partnership purposes, including possible acquisitions. Proceeds from the at-the-market equity issuance were used for general limited partnership purposes.

Class B Preferred Unit Offering

On October 14, 2015, pursuant to that certain Class B Preferred Unit Purchase Agreement dated September 25, 2015 between the Partnership and Stonepeak Catarina Holdings LLC (“Stonepeak”), the Partnership sold and Stonepeak purchased 19,444,445 of the Partnership’s newly created Class B Preferred Units (the “Class B Preferred Units”) in a privately negotiated transaction for an aggregate cash purchase price of $18.00 per Class B Preferred Unit, which resulted in gross proceeds to the Partnership of approximately $350.0 million. The Partnership used the net proceeds to pay a portion of the consideration for the acquisition of Western Catarina Midstream, along with the payment to Stonepeak of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

Under the terms of our partnership agreement, holders of the Class B Preferred Units receive a quarterly distribution, at the election of the board of directors of our general partner, of 10.0% per annum if paid in full in cash or 12.0% per annum if paid in part cash (8.0%

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per annum) and in part paid-in-kind units (4.0% per annum). Distributions are to be paid on or about the last day of each of February, May, August and November after the end of each quarter.

In accordance with the partnership agreement, on December 6, 2016 we issued an additional 9,851,996 Class B Preferred Units to Stonepeak. On January 25, 2017, the Partnership and Stonepeak entered into a Settlement Agreement and Mutual Release (the "Settlement Agreement") to settle a dispute arising from the calculation of an adjustment to the number of Class B Preferred Units pursuant to Section 5.10(g) of the Second Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended Partnership Agreement"). Pursuant to the Settlement Agreement, and in accordance with Section 5.4 of the Amended Partnership Agreement, the Partnership issued 1,704,446 Class B Preferred Units to Stonepeak in a privately negotiated transaction as partial consideration for the Settlement Agreement, with the "Class B Preferred Unit Price" being established at $11.29 per Class B Preferred Unit. Pursuant to the terms of the Amended Partnership Agreement, the Class B Preferred Units are convertible at any time, at the option of Stonepeak, into common units of the Partnership, subject to the requirement to convert a minimum of $17.5 million of Class B Preferred Units. The issuance of the Class B Preferred Units pursuant to the Settlement Agreement was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933 pursuant to Section 4(a)(2) thereof.

The Class B Preferred Units are accounted for as mezzanine equity on the consolidated balance sheet. The following table sets forth a reconciliation of the changes in mezzanine equity (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Mezzanine equity beginning balance	$ 343,912	$ 342,991
Amortization of discount	1,099	1,796
Distributions	19,250	35,875
Distributions paid	(17,500)	(36,750)
Total mezzanine equity	$ 346,761	$ 343,912

Earnings per Unit

Net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income (loss) based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. The two-class method dictates that net income (loss) for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income (loss) be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income (loss) as if all of the net income for the period had been distributed in accordance with the partnership agreement. Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income (loss) per unit. Undistributed income (loss) is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units based on provisions of the partnership agreement. Undistributed losses are not allocated to unvested restricted unit awards as they do not participate in net losses. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

Our general partner does not have an economic interest in the Partnership and, therefore, does not participate in the Partnership's net income.

17. REPORTING SEGMENTS

"Midstream" and "Production" best describe the operating segments of the businesses that we separately report. The factors used to identify these reporting segments are based on the nature of the operations that are undertaken by each segment. The Midstream segment operates the gathering, processing and transportation of crude oil, natural gas and NGLs. The Production segment operates to produce crude oil and natural gas. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the Partnership because they are the segments (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Partnership's chief operating decision maker ("CODM") to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available. Operating segments are evaluated for their contribution to the Partnership's consolidated results based on operating income, which is defined as segment operating revenues less expenses.

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	Three Months Ended June 30,			
	2018		2017	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 226	$ —	$ 2,252	$ —
Oil sales	1,584	—	8,109	—
Natural gas liquid sales	400	—	492	—
Gathering and transportation sales	—	1,661	—	14,176
Gathering and transportation lease revenues	—	13,168	—	—
Total segment revenues	2,210	14,829	10,853	14,176
Segment operating costs				
Lease operating expenses	1,644	363	3,648	233
Transportation operating expenses	—	3,071	—	3,032
Cost of sales	—	—	40	—
Production taxes	287	—	353	—
Gain on sale of assets	(2,388)	—	—	—
Depreciation, depletion and amortization	1,251	5,294	2,924	6,013
Accretion expense	49	74	172	68
Total segment operating costs	843	8,802	7,137	9,346
Segment other income				
Earnings from equity investments	—	3,111	27	1,015
Total segment other income	—	3,111	27	1,015
Segment operating income	$ 1,367	$ 9,138	$ 3,743	$ 5,845

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	Six Months Ended June 30,			
	2018		2017	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 699	$ —	$ 5,031	$ —
Oil sales	5,046	—	19,459	—
Natural gas liquid sales	995	—	959	—
Gathering and transportation sales	—	3,349	—	25,387
Gathering and transportation lease revenues	—	25,486	—	—
Total segment revenues	6,740	28,835	25,449	25,387
Segment operating costs				
Lease operating expenses	3,396	582	8,372	492
Transportation operating expenses	—	5,918	—	6,328
Cost of sales	—	—	77	—
Production taxes	609	—	826	—
Gain on sale of assets	(2,388)	—	—	—
Depreciation, depletion and amortization	2,614	10,559	6,205	14,913
Asset impairments	—	—	4,688	—
Accretion expense	103	146	364	134
Total segment operating costs	4,334	17,205	20,532	21,867
Segment other income (loss)				
Earnings (loss) from equity investments	—	7,383	(109)	1,633
Total segment other income (loss)	—	7,383	(109)	1,633
Segment operating income	$ 2,406	$ 19,013	$ 4,808	$ 5,153

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Reconciliation of segment operating income to net income (loss)				
Total production operating income	$ 1,367	$ 3,743	$ 2,406	$ 4,808
Total midstream operating income	9,138	5,845	19,013	5,153
Total segment operating income	10,505	9,588	21,419	9,961
General and administrative expense	(6,919)	(6,353)	(12,084)	(11,962)
Unit-based compensation expense	(1,347)	(780)	(2,785)	(1,320)
Interest expense, net	(2,780)	(1,896)	(5,379)	(3,779)
Other expense(a)	(1,254)	—	(1,524)	—
Net income (loss)	$ (1,795)	$ 559	$ (353)	(7,100)

(a)

Other expense in 2017 excludes earnout rebate. As the rebate is reviewed by the CODM at the segment level, it was included in the Midstream segment operating costs.

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The following table summarizes the total assets and capital expenditures by operating segment based on the segment realignment as of June 30, 2018 and December 31, 2017 (in thousands):

	June 30, 2018			
	Production	Midstream	Corporate (a)	Total
Other financial information				
Total assets	$ 53,240	$ 446,800	$ 3,382	$ 503,422
Capital expenditures(b)	$ 205	$ 3,940	$ —	$ 4,145

	December 31, 2017			
	Production	Midstream	Corporate (a)	Total
Other financial information				
Total assets	$ 58,623	$ 468,656	$ 1,144	$ 528,423
Capital expenditures(b)	$ 441	$ 46,452	$ —	$ 46,893

(a) Corporate assets not reviewed by the CODM on a segment basis consists of cash, certain prepaids, office furniture, and other assets.
(b) Inclusive of capital contributions made to equity method investments.

18. VARIABLE INTEREST ENTITIES

The Partnership’s investment in Carnero JV represents a VIE that could expose the Partnership to losses. The amount of losses the Partnership could be exposed to from Carnero JV is limited to the capital investment of approximately $120.7 million.

As of June 30, 2018, the Partnership had invested approximately $123.7 million in Carnero JV and no debt has been incurred by Carnero JV. We have included this VIE in the “Equity investments” long-term asset line on the balance sheet.

Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Partnership’s maximum exposure to loss as of June 30, 2018 and December 31, 2017 (in thousands):

	June 30, 2018	December 31, 2017
Acquisitions and capital investments	$ 127,774	$ 125,059

Earnings in equity investments	17,669	10,288
Distributions received	(24,733)	(11,632)
Maximum exposure to loss	$ 120,710	$ 123,715

19. SUBSEQUENT EVENTS

On August 8, 2018, the board of directors of our general partner declared a second quarter 2018 cash distribution on the Partnership's common units of $0.4508 per unit ($1.8032 per unit annualized) payable on August 31, 2018 to the holders of record on August 21, 2018. The Partnership also declared a second quarter distribution on the Class B Preferred Units and elected to pay the distribution in part cash and in part Class B Preferred Units. Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B Preferred Unit and an aggregate distribution of 310,009 Class B Preferred PIK Units, each payable on August 31, 2018 to holders of record on August 21, 2018.

On August 8, 2018, the Partnership received an additional commitment of $10.0 million under the Credit Agreement, which increased the facility's elected commitment amount from $200.0 million to $210.0 million. As of August 8, 2018 we had $184.0 million of debt outstanding under the facility, leaving us with $26.0 million in unused borrowing capacity.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the financial statements and the summary of significant accounting policies and notes included herein and in our most recent Annual Report on Form 10-K. The following discussion contains "Forward-Looking Statements" that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The "Forward-Looking Statements" are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these "Forward-Looking Statements." Please read "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. The Partnership has ownership stakes in oil and natural gas gathering systems, natural gas pipelines, and a natural gas processing facility, all located in the Western Eagle Ford in South Texas. Our assets include our wholly-owned Western Catarina Midstream gathering system, our wholly-owned Seco Pipeline, and a 50% interest in Carnero JV, a 50/50 joint venture operated by Targa that owns the Carnero Gathering Line, Raptor Gas Processing Facility, and Silver Oak II, and reversionary working interests and other production assets in Texas and Louisiana. On June 2, 2017, Sanchez Production Partners LP changed its name to Sanchez Midstream Partners LP. Manager owns the general partner of SNMP and all of SNMP's incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol "SNMP."

How We Evaluate Our Operations

We evaluate our business on the basis of the following key measures:

- our throughput volumes on gathering systems upon acquiring those assets;
- our operating expenses; and
- our Adjusted EBITDA, a non-GAAP financial measure (for a reconciliation of Adjusted EBITDA to the most comparable GAAP financial measure please read "—Non-GAAP Financial Measures–Adjusted EBITDA").

Throughput Volumes

Upon the acquisition of Western Catarina Midstream, our management began to analyze our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within the dedicated areas in order to maintain or increase throughput volumes on Western Catarina Midstream. Our success in connecting additional wells is impacted by successful drilling activity by Sanchez Energy on the acreage dedicated to Western Catarina Midstream, our ability to secure volumes from Sanchez Energy from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure. Construction of the Seco Pipeline was completed in August 2017, and throughput volumes are dependent on gas processed at the Raptor Gas Processing Facility and demand for dry gas in markets in South Texas. Natural gas is currently being transported through the Seco Pipeline under the Seco Pipeline Transportation Agreement. Future throughput volumes on the pipeline are dependent on the continuation of this month-to-month agreement with Sanchez Energy, execution of a new agreement with Sanchez Energy or execution of an agreement with a third party.

Operating Expenses

Our management seeks to maximize Adjusted EBITDA, a non-GAAP financial measure, in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (which generally consists of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, among other items), compression expense, ad valorem taxes and other operating costs, some of which will be independent of our oil and natural gas production or the throughput volumes on the gathering system but fluctuate depending on the scale of our operations during a specific period.

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Non-GAAP Financial Measures—Adjusted EBITDA

To supplement our financial results and guidance presented in accordance with U.S. generally accepted accounting principles (“GAAP”), we use Adjusted EBITDA, a non-GAAP financial measure, in this quarterly report. We believe that non-GAAP financial measures are helpful in understanding our past financial performance and potential future results, particularly in light of the effect of various transactions effected by us. We define Adjusted EBITDA as net income (loss) adjusted by: (i) interest (income) expense, net, which includes interest expense, interest expense net (gain) loss on interest rate derivative contracts, and interest (income); (ii) income tax expense (benefit); (iii) depreciation, depletion and amortization; (iv) asset impairments; (v) accretion expense; (vi) (gain) loss on sale of assets; (vii) unit-based compensation expense; (viii) unit-based asset management fees; (ix) distributions in excess of equity earnings; (x) (gain) loss on mark-to-market activities; (xi) commodity derivatives settled early; (xii) (gain) loss on embedded derivatives; and (xiii) acquisition and divestiture costs.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by the board of directors of our general partner) the distributions that we would expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain or support a quarterly distribution or any increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess: (i) the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and (iii) our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We believe that the presentation of Adjusted EBITDA provides useful information to investors in assessing our financial condition and results of operations. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss). Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income (loss). Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income (loss). Adjusted EBITDA should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following table sets forth a reconciliation of Adjusted EBITDA to net income (loss), its most directly comparable GAAP performance measure, for each of the periods presented (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss)	$ (1,795)	$ 559	$ (353)	$ (7,100)
Adjusted by:				
Interest expense, net	2,780	1,896	5,379	3,779
Depreciation, depletion and amortization	6,545	8,937	13,173	21,118
Asset impairments	—	—	—	4,688
Accretion expense	123	240	249	498
Gain on sale of assets	(2,388)	—	(2,388)	—
Unit-based compensation expense	1,347	1,479	2,785	2,019
Unit-based asset management fees	2,647	2,345	4,926	4,375

Distributions in excess of equity earnings	2,360	803	4,197	1,771
(Gain) loss on mark-to-market activities	4,453	(1,347)	6,431	(5,827)
Acquisition and divestiture costs	1,529	424	1,780	553
Adjusted EBITDA	$ 17,601	$ 15,336	$ 36,179	$ 25,874

Significant Operational Factors

· Throughput. During the three months ended June 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.0 MBbls/d of crude oil, 155.4 MMcf/d of natural gas and 11.8 MBbls/d of water. During the three months ended June 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.5 MBbls/d of crude oil, 169.6 MMcf/d of natural gas and 16.9 MBbls/d of water. During the three months ended June 30, 2018 Sanchez Energy transported average daily production through the Seco Pipeline of approximately 52.7 MMcf/d of natural gas. During the three and six months ended June 30, 2017 Sanchez Energy did not transport production through the Seco Pipeline as the pipeline was not yet operational. During the six months ended June 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.7 MBbls/d of crude oil, 153.6 MMcf/d of natural gas and 10.2 MBbls/d of water. During the six months ended June 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.4 MBbls/d of crude oil, 160.7 MMcf/d of natural gas and 8.5 MBbls/d of water. During the six months ended June 30, 2018 Sanchez Energy transported average daily production through the Seco Pipeline of approximately 60.3 MMcf/d of natural gas.

- Production. Our production for the three months ended June 30, 2018, was 118 MBoe, or an average of 1,297 Boe/d, compared with approximately 290 MBoe, or an average of 3,187 Boe/d, for the three months ended June 30, 2017. Our production for the six months ended June 30, 2018, was 259 MBoe, or an average of 1,431 Boe/d, compared with approximately 600 MBoe, or an average of 3,315 Boe/d, for the six months ended June 30, 2017. The decreases in production are primarily attributable to the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.
- Capital Expenditures. For the three months ended June 30, 2018, we spent approximately $0.4 million in capital expenditures, related to the development of Western Catarina Midstream and $0.5 million related to the development of the Seco Pipeline. For the three months ended June 30, 2017, we spent approximately $10.9 million in capital expenditures, consisting of $9.8 million related to the development of the Seco Pipeline and $1.1 million related to the development of Western Catarina Midstream. For the six months ended June 30, 2018, we spent approximately $0.8 million in capital expenditures, related to the development of Western Catarina Midstream and $0.5 million related to the development of the Seco Pipeline. For the six months ended June 30, 2017, we spent approximately $24.0 million in capital expenditures, consisting of $21.7 million related to the development of the processing facility and $2.3 million related to the development of Western Catarina Midstream.
- Hedging Activities. For the three months ended June 30, 2018, the non-cash mark-to-market loss for our commodity derivatives was approximately $3.2 million, compared to a gain of $1.3 million for the same period in 2017. For the six months ended June 30, 2018, the non-cash mark-to-market loss for our commodity derivatives was approximately $4.9 million, compared to a gain of $5.8 million for the same period in 2017.

Recent Developments

On August 8, 2018, the board of directors of our general partner declared a second quarter 2018 cash distribution on the Partnership's common units of $0.4508 per unit ($1.8032 per unit annualized) payable on August 31, 2018 to the holders of record on August 21, 2018. The Partnership also declared a second quarter distribution on the Class B Preferred Units and elected to pay the distribution in part cash and in part Class B Preferred Units. Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B Preferred Unit and an aggregate distribution of 310,009 Class B Preferred PIK Units, each payable on August 31, 2018 to holders of record on August 21, 2018.

Results of Operations by Segment

Three months ended June 30, 2018 compared to three months ended June 30, 2017

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

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	Three Months Ended June 30, 2018	2017	Variance		
Revenues:					
Gathering and transportation sales	$ 1,661	$ 14,176	$ (12,515)	(88)	%
Gathering and transportation lease revenues	13,168	—	13,168	NM	(a)
Total gathering and transportation sales	14,829	14,176	653	5	%
Operating expenses:					
Lease operating expenses	363	233	130	56	%
Transportation operating expenses	3,071	3,032	39	1	%
Depreciation and amortization	5,294	6,013	(719)	(12)	%
Accretion expense	74	68	6	9	%
Total operating expenses	8,802	9,346	(544)	(6)	%
Other income:					
Earnings from equity investments	3,111	1,015	2,096	NM	(a)
Operating income	$ 9,138	$ 5,845	$ 3,293	56	%

(a) Variances deemed to be Not Meaningful “NM.”

Gathering and transportation sales. During the three months ended June 30, 2018, Sanchez Energy transported average daily production through the Seco Pipeline of approximately 52.7 MMcf/d of natural gas.

Gathering and transportation lease revenues. We consummated the acquisition of Western Catarina Midstream from Sanchez Energy and entered into the related Gathering Agreement with Sanchez Energy in October 2015. On June 30, 2017, the Gathering Agreement with Sanchez Energy was amended to add an incremental infrastructure fee to be paid by SN Catarina based on water that is delivered through the gathering system through March 31, 2018. The parties have agreed to continue the incremental infrastructure fee on a month-to-month basis. During the three months ended June 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.0 MBbls/d of crude oil, 155.4 MMcf/d of natural gas and 11.8 MBbls/d of water. During the three months ended June 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.5 MBbls/d of crude oil, 169.6 MMcf/d of natural gas and 16.9 MBbls/d of water.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, increased $0.2 million to $0.4 million for the three months ended June 30, 2018 compared to $0.2 million during the same period in 2017. The increase was related to increased ad valorem taxes related to the Seco Pipeline.

Transportation operating expenses. Our operating expenses generally consist of equipment rentals, chemicals, treating, metering fees, permit and regulatory fees, labor, minor maintenance, tools, supplies, and integrity management expenses. Our transportation operating expenses remained flat for the three months ended June 30, 2018 and 2017.

Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense decreased $0.7 million, or 12%, to $5.3 million for the three months ended June 30, 2018, compared to $6.0 million during the same period in 2017. This decrease was the result of certain midstream assets becoming fully depreciated in June 2017.

Earnings from equity investments. Earnings from equity investments increased \$2.1 million to \$3.1 million for the three months ended June 30, 2018, compared to \$1.0 million for the same period in 2017. This increase was the result of benefitting from earnings in the Raptor Gas Processing Facility for the full three months ended June 30, 2018.

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Production Operating Results

The following tables set forth the selected financial and operating data pertaining to the Production segment for the periods indicated (in thousands, except net production and average sales and costs):

	Three Months Ended June 30, 2018	2017	Variance		
Revenues:					
Natural gas sales at market price	$ 224	$ 2,130	$ (1,906)	(89)	%
Natural gas hedge settlements	26	651	(625)	(96)	%
Natural gas mark-to-market activities	(24)	(486)	462	(95)	%
Natural gas total	226	2,295	(2,069)	(90)	%
Oil sales at market price	5,301	5,061	240	5	%
Oil hedge settlements	(542)	1,215	(1,757)	NM	(a)
Oil mark-to-market activities	(3,175)	1,833	(5,008)	NM	(a)
Oil total	1,584	8,109	(6,525)	(80)	%
NGL sales	400	492	(92)	(19)	%
Miscellaneous expense	—	(43)	43	(100)	%
Total revenues	2,210	10,853	(8,643)	(80)	%
Operating expenses:					
Lease operating expenses	1,644	3,648	(2,004)	(55)	%
Cost of sales	—	40	(40)	(100)	%
Production taxes	287	353	(66)	(19)	%
Gain on sale of assets	(2,388)	—	(2,388)	NM	(a)
Depreciation, depletion and amortization	1,251	2,924	(1,673)	(57)	%
Accretion expense	49	172	(123)	(72)	%
Total operating expenses	843	7,137	(6,294)	(88)	%
Other income:					
Earnings from equity investments	—	27	(27)	(100)	%
Operating income	$ 1,367	$ 3,743	$ (2,376)	(63)	%

(a) Variances deemed to be Not Meaningful "NM."

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	Three Months Ended June 30, 2018	2017	Variance	
Net production:				
Natural gas (MMcf)	124	925	(801)	(87)%
Oil production (MBbl)	79	110	(31)	(28)%
NGLs (MBbl)	18	26	(8)	(31)%
Total production (MBoe)	118	290	(172)	(59)%
Average daily production (Boe/d)	1,297	3,187	(1,890)	(59)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 2.02	$ 3.01	$ (0.99)	(33)%
Natural gas price per Mcf without hedge settlements	$ 1.81	$ 2.30	$ (0.49)	(21)%
Oil price per Bbl with hedge settlements	$ 60.24	$ 57.05	$ 3.19	6 %
Oil price per Bbl without hedge settlements	$ 67.10	$ 46.01	$ 21.09	46 %
Liquid price per Bbl without hedge settlements	$ 22.22	$ 18.92	$ 3.30	17 %
Total price per Boe with hedge settlements	$ 45.84	$ 32.93	$ 12.91	39 %
Total price per Boe without hedge settlements	$ 50.21	$ 26.49	$ 23.72	90 %
Average unit costs per Boe:				
Field operating expenses (a)	$ 16.36	$ 13.80	$ 2.56	19 %
Lease operating expenses	$ 13.93	$ 12.58	$ 1.35	11 %
Production taxes	$ 2.43	$ 1.22	$ 1.21	99 %
Depreciation, depletion and amortization	$ 10.60	$ 10.08	$ 0.52	5 %

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.
Production. For the three months ended June 30, 2018, 67% of our production was oil, 15% was NGLs and 18% was natural gas as compared to the three months ended June 30, 2017, where 38% of our production was oil, 9% was NGLs and 53% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2017. Combined production has decreased by 172 MBoe for the three months ended June 30, 2018, primarily due to the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

Natural gas, NGLs and oil sales. Unhedged oil sales increased $0.2 million, or 5%, to $5.3 million for the three months ended June 30, 2018, compared to $5.1 million for the same period in 2017. NGL sales decreased $0.1 million, or 19%, to 0.4 million for the three months ended June 30, 2018, compared to $0.5 million for the same period in 2017. Unhedged natural gas sales decreased $1.9 million, or 89%, to $0.2 million for the three months ended June 30, 2018, compared to $2.1 million for the same period in 2017. Total decrease in oil, NGL and natural gas sales for the three months ended June 30, 2018 was primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

Including hedges and mark-to-market activities, our total revenue decreased $8.7 million for the three months ended June 30, 2018, compared to the same period in 2017. This decrease was primarily the result of a $4.5 million decrease in mark-to-market activities, $2.4 million decrease in settlements on oil and natural gas derivatives, and a $1.9 million decrease in natural gas sales.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the three months ended June 30, 2018 to the three months ended

June 30, 2017 (dollars in thousands, except average sales price):

	Q2 2018 Production Volume	Q2 2017 Production Volume	Production Volume Difference	Q2 2017 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	124	925	(801)	$ 2.30	$ (1,842)
Oil (MBbl)	79	110	(31)	$ 46.01	$ (1,426)
Natural gas liquids (MBbl)	18	26	(8)	$ 18.92	$ (151)
Total oil equivalent (MBoe)	118	290	(172)	$ 26.49	$ (3,419)

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	Q2 2018 Average Sales Price	Q2 2017 Average Sales Price	Average Sales Price Difference	Q2 2018 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (MMcf)	$ 1.81	$ 2.30	$ (0.49)	124	$ (61)
Oil (MBbl)	$ 67.10	$ 46.01	$ 21.09	79	$ 1,666
Natural gas liquids (MBbl)	$ 22.22	$ 18.92	$ 3.30	18	$ 59
Total oil equivalent (MBoe)	$ 50.21	$ 26.49	$ 23.72	118	$ 1,664

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the three months ended June 30, 2018 by $0.6 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the three months ended June 30, 2018, the non-cash mark-to-market loss was $3.2 million, compared to a gain of $1.3 million for the same period in 2017. The 2018 non-cash loss resulted from higher future expected oil prices on these derivative transactions. Cash settlements paid for our commodity derivatives were $0.5 million for the three months ended June 30, 2018, compared to cash settlements received of $1.9 million for the three months ended June 30, 2017.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, decreased $2.0 million, or 55% to $1.6 million for the three months ended June 30, 2018, compared to $3.6 million during the same period in 2017. The decrease for the comparative periods was primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the three months ended June 30, 2018 was $1.3 million, compared to $2.9 million for the same period in 2017. This decrease is primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture. Our non-oil and natural gas properties are depreciated using the straight-line basis.

Impairment expense. For the three months ended June 30, 2018, and 2017 we did not record impairment charges.

Consolidated Earnings Results

The following table sets forth the reconciliation of segment operating income to net income (loss) for periods indicated (in thousands):

Three Months Ended

	June 30, 2018	2017	Variance		
Reconciliation of segment operating income to net income (loss)					
Total production operating income	$ 1,367	$ 3,743	$ (2,376)	(63)	%
Total midstream operating income	9,138	5,845	3,293	56	%
Total segment operating income	10,505	9,588	917	10	%
General and administrative expense	(6,919)	(6,353)	(566)	9	%
Unit-based compensation expense	(1,347)	(780)	(567)	73	%
Interest expense, net	(2,780)	(1,896)	(884)	47	%
Other expense(b)	(1,254)	—	(1,254)	NM	(a)
Net income (loss)	$ (1,795)	$ 559	$ (2,354)	NM	(a)

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(a) Variances deemed to be Not Meaningful "NM."

(b) Other expense in 2017 excludes earnout rebate. As the rebate is reviewed by the CODM at the segment level, it was included in the Midstream segment operating costs.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, increased to $8.3 million for the three months ended June 30, 2018, compared to $7.1 million for the same period in 2017. This increase was primarily driven by a litigation settlement paid during the three months ended June 30, 2018.

Interest expense, net. Interest expense increased $0.9 million, to $2.8 million for the three months ended June 30, 2018, compared to $1.9 million for the same period in 2017. This increase was the result of net draws on our Credit Agreement, primarily to fund capital projects in our joint ventures with Targa and development of the Seco Pipeline.

Six months ended June 30, 2018 compared to six months ended June 30, 2017

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

	Six Months Ended June 30,				
	2018	2017	Variance		
Revenues:					
Gathering and transportation sales	$ 3,349	$ 25,387	$ (22,038)	(87)	%
Gathering and transportation lease revenues	25,486	—	25,486	NM	(a)
Total gathering and transportation sales	28,835	25,387	3,448	14	%
Operating costs:					
Lease operating expenses	582	492	90	18	%
Transportation operating expenses	5,918	6,328	(410)	(6)	%
Depreciation and amortization	10,559	14,913	(4,354)	(29)	%
Accretion expense	146	134	12	9	%
Total operating expenses	17,205	21,867	(4,662)	(21)	%
Other income:					
Earnings from equity investments	7,383	1,633	5,750	NM	(a)
Operating income	$ 19,013	$ 5,153	$ 13,860	NM	(a)

(a) Variances deemed to be Not Meaningful "NM."

Gathering and transportation sales. During the six months ended June 30, 2018, Sanchez Energy transported average daily production through the Seco Pipeline of approximately 60.3 MMcf/d of natural gas.

Gathering and transportation lease revenues. We consummated the acquisition of Western Catarina Midstream from Sanchez Energy and entered into the related Gathering Agreement with Sanchez Energy in October 2015. On June 30, 2017, the Gathering Agreement with Sanchez Energy was amended to add an incremental infrastructure fee to be paid by SN Catarina based on water that is delivered through the gathering system through March 31, 2018. The parties have agreed to continue the incremental infrastructure fee on a month-to-month basis. During the six months ended June 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.7 MBbls/d of crude oil, 153.6 MMcf/d of natural gas and 10.2 MBbls/d of water. During the six months ended June 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.4 MBbls/d of crude oil, 160.7 MMcf/d of natural gas and 8.5 MBbls/d of water.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, increased $0.1 million to $0.6 million for the six months ended June 30, 2018 compared to $0.5 million during the same period in 2017. The increase was related to increased ad valorem taxes related to the Seco Pipeline.

Transportation operating expenses. Our operating expenses generally consist of equipment rentals, chemicals, treating, metering fees, permit and regulatory fees, labor, minor maintenance, tools, supplies, and integrity management expenses. Our transportation operating expenses decreased $0.4 million to $5.9 million for the six months ended June 30, 2018, compared to $6.3 million during the same period in 2017, which was due to fewer repairs and maintenance on our midstream assets.

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Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense decreased $4.3 million, or 29%, to $10.6 million for the six months ended June 30, 2018, compared to $14.9 million during the same period in 2017. This decrease was the result of certain midstream assets becoming fully depreciated in June 2017.

Earnings from equity investments. Earnings from equity investments increased $5.8 million to $7.4 million for the six months ended June 30, 2018, compared to $1.6 million for the same period in 2017. This increase was the result of benefitting from earnings in the Raptor Gas Processing Facility for the full six months ended June 30, 2018.

Production Operating Results

The following tables set forth the selected financial and operating data pertaining to the Production segment for the periods indicated (in thousands, except net production and average sales and costs):

	Six Months Ended June 30,				
	2018	2017	Variance		
Revenues:					
Natural gas sales at market price	$ 695	$ 4,406	$ (3,711)	(84)	%
Natural gas hedge settlements	26	1,297	(1,271)	(98)	%
Natural gas mark-to-market activities	(22)	(572)	550	96	%
Natural gas total	699	5,131	(4,432)	(86)	%
Oil sales	10,703	10,916	(213)	(2)	%
Oil hedge settlements	(772)	2,144	(2,916)	NM	(a)
Oil mark-to-market activities	(4,885)	6,399	(11,284)	NM	(a)
Oil total	5,046	19,459	(14,413)	(74)	%
NGL sales	995	959	36	4	%
Miscellaneous expense	—	(100)	100	100	%
Total revenues	6,740	25,449	(18,709)	(74)	%
Operating costs:					
Lease operating expenses	3,396	8,372	(4,976)	(59)	%
Cost of sales	—	77	(77)	(100)	%
Production taxes	609	826	(217)	(26)	%
Gain on sale of assets	(2,388)	—	(2,388)	NM	(a)
Depreciation, depletion and amortization	2,614	6,205	(3,591)	(58)	%
Asset impairments	—	4,688	(4,688)	(100)	%
Accretion expense	103	364	(261)	(72)	%
Total operating expenses	4,334	20,532	(16,198)	(79)	%
Other income:					
Earnings from equity investments	—	(109)	109	(100)	%
Operating income	$ 2,406	$ 4,808	$ (2,402)	(50)	%

(a) Variances deemed to be Not Meaningful "NM."

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	Six Months Ended June 30, 2018	2017	Variance		
Net production:					
Natural gas (MMcf)	306	1,903	(1,597)	(84)	%
Oil production (MBbl)	164	230	(66)	(29)	%
NGLs (MBbl)	44	53	(9)	(17)	%
Total production (MBoe)	259	600	(341)	(57)	%
Average daily production (Boe/d)	1,431	3,315	(1,884)	(57)	%
Average sales prices:					
Natural gas price per Mcf with hedge settlements	$ 2.36	$ 3.00	$ (0.64)	(21)	%
Natural gas price per Mcf without hedge settlements	$ 2.27	$ 2.32	$ (0.05)	(2)	%
Oil price per Bbl with hedge settlements	$ 60.55	$ 56.78	$ 3.77	7	%
Oil price per Bbl without hedge settlements	$ 65.26	$ 47.46	$ 17.80	38	%
Liquid price per Bbl without hedge settlements	$ 22.61	$ 18.09	$ 4.52	25	%
Total price per Boe with hedge settlements	$ 44.97	$ 32.87	$ 12.10	37	%
Total price per Boe without hedge settlements	$ 47.85	$ 27.14	$ 20.71	76	%
Average unit costs per Boe:					
Field operating expenses (a)	$ 15.46	$ 15.33	$ 0.13	1	%
Lease operating expenses	$ 13.11	$ 13.95	$ (0.84)	(6)	%
Production taxes	$ 2.35	$ 1.38	$ 0.97	70	%
Depreciation, depletion and amortization	$ 10.09	$ 10.34	$ (0.25)	(2)	%

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Production. For the six months ended June 30, 2018, 63% of our production was oil, 17% was NGLs and 20% was natural gas as compared to the six months ended June 30, 2017, where 38% of our production was oil, 9% was NGLs and 53% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2017. Combined production has decreased by 341 MBoe for the six months ended June 30, 2018, primarily due to the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

Natural gas, NGLs and oil sales. Unhedged oil sales decreased $0.2 million, or 2%, to $10.7 million for the six months ended June 30, 2018, compared to $10.9 million for the same period in 2017. NGL sales remained flat for the six months ended June 30, 2018 and 2017. Unhedged natural gas sales decreased $3.7 million, or 84%, to $0.7 million for the six months ended June 30, 2018, compared to $4.4 million for the same period in 2017. Total decrease in oil, NGL and natural gas sales for the six months ended June 30, 2018 was primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

Including hedges and mark-to-market activities, our total revenue decreased $18.7 million for the six months ended June 30, 2018, compared to the same period in 2017. This decrease was primarily the result of a $10.7 million decrease in mark-to-market activities, a $4.2 million decrease in settlements on oil and natural gas derivatives, and a $3.7 million decrease in natural gas sales.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the six months ended June 30, 2018 to the six months ended June 30, 2017 (dollars in thousands, except average sales price):

	2018 Production Volume	2017 Production Volume	Production Volume Difference	2017 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	306	1,903	(1,597)	$ 2.32	$ (3,705)
Oil (MBbl)	164	230	(66)	$ 47.46	$ (3,132)
NGLs (MBbl)	44	53	(9)	$ 18.09	$ (163)
Total oil equivalent (MBoe)	259	600	(341)	$ 27.14	$ (7,000)

	2018 Average Sales Price	2017 Average Sales Price	Average Sales Price Difference	2018 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (MMcf)	$ 2.27	$ 2.32	$ (0.05)	306	$ (15)
Oil (MBbl)	$ 65.26	$ 47.46	$ 17.80	164	$ 2,919
NGLs (MBbl)	$ 22.61	$ 18.09	$ 4.52	44	$ 199
Total oil equivalent (MBoe)	$ 47.85	$ 27.14	$ 20.71	259	$ 3,103

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A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the six months ended June 30, 2018 by $1.2 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the six months ended June 30, 2018, the non-cash mark-to-market loss was $4.9 million, compared to a gain of $5.8 million for the same period in 2017. The 2018 non-cash loss resulted from higher future expected oil prices on these derivative transactions. Cash settlements paid for our commodity derivatives were $0.7 million for the six months ended June 30, 2018, compared to cash settlements received of $3.4 million for the six months ended June 30, 2017.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses decreased $5.0 million, or 59%, to $3.4 million for the six months ended June 30, 2018, compared to $8.4 million during the same period in 2017. The decreased lease operating expenses for the comparative periods were primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2018 was $2.6 million compared to $6.2 million for the same period in 2017. This decrease is primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture. Our non-oil and natural gas properties are depreciated using the straight-line basis.

Impairment expense. For the six months ended June 30, 2018, we did not record impairment charges. For the six months ended June 30, 2017, we recorded non-cash charges of $4.7 million to impair certain of our producing oil and natural gas properties in Texas.

Consolidated Earnings Results

The following table sets forth the reconciliation of segment operating income to net income (loss) for periods indicated (in thousands):

	Six Months Ended June 30, 2018	2017	Variance	
Reconciliation of segment operating income to net income (loss)				
Total production operating income	$ 2,406	$ 4,808	$ (2,402)	(50) %
Total midstream operating income	19,013	5,153	13,860	NM (a)
Total segment operating income	21,419	9,961	11,458	NM (a)
General and administrative expense	(12,084)	(11,962)	(122)	1 %

Unit-based compensation expense	(2,785)	(1,320)	(1,465)	NM (a)
Interest expense, net	(5,379)	(3,779)	(1,600)	42 %
Other expense(b)	(1,524)	—	(1,524)	NM (a)
Net income (loss)	$ (353)	$ (7,100)	$ 6,747	(95) %

(a) Variances deemed to be Not Meaningful "NM."

(b) Other expense in 2017 excludes earnout rebate. As the rebate is reviewed by the CODM at the segment level, it was included in the Midstream segment operating costs.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, increased to $14.9 million for the six months ended June 30, 2018, compared to $13.3 million for the same period in 2017. This increase was primarily driven by a litigation settlement paid during the six months ended June 30, 2018.

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Interest expense, net. Interest expense increased $1.6 million, or 42%, to $5.4 million for the six months ended June 30, 2018, compared to $3.8 million for the same period in 2017. This increase was the result of net draws on our Credit Agreement, primarily to fund capital projects in our joint ventures with Targa and development of the Seco Pipeline.

Liquidity and Capital Resources

As of June 30, 2018, we had approximately $2.5 million in cash and cash equivalents and $16.0 million available for borrowing under the Credit Agreement in effect on such date. During the three months ended June 30, 2018, we paid approximately $2.5 million in cash for interest on borrowings under our Credit Agreement and approximately $20.2 thousand in cash for the commitment fee on undrawn commitments. For the six months ended June 30, 2018, we paid approximately $4.8 million in cash for interest on borrowings under our Credit Agreement and approximately $34.2 thousand in cash for the commitments fee on undrawn commitments.

Our capital expenditures during the three and six months ended June 30, 2018 were funded with cash on hand. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional limited partner units. We expect that the combination of these capital resources will be adequate to meet our short-term working capital requirements, long-term capital expenditures program and expected quarterly cash distributions.

We expect that our future cash requirements relating to working capital, maintenance capital expenditures and quarterly cash distributions to our partners will be funded from cash flows internally generated from our operations. Our expansion capital expenditures will be funded by borrowings under our Credit Agreement or from potential capital market transactions. However, there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our current debt level, planned levels of capital expenditures, operating expenses or any cash distributions that we may make to unitholders.

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto. The Credit Agreement provides a maximum commitment of $500.0 million and has a maturity date of March 31, 2020. Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that we own, as well as various security and pledge agreements among the Partnership, certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of $15.0 million, which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was $200.0 million. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is generally equal to the rolling four quarter Adjusted EBITDA of our midstream operations, together with the amount of distributions received from Carnero JV multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of our lenders. As of June 30, 2018, the borrowing base under the Credit Agreement was $310.0 million, with an elected commitment amount of $200.0 million.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) LIBOR plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) ABR plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus (iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

· Current assets to current liabilities for at least 1.0 to 1.0 at all times;

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- Senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the adjusted EBITDA of our midstream operations equals or exceeds one-third of total Adjusted EBITDA or 4.0 to 1.0 if the adjusted EBITDA of our midstream operations is less than one-third of total adjusted EBITDA; and
- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At June 30, 2018, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Sources of Debt and Equity Financing

As of June 30, 2018, the elected commitment amount under our Credit Agreement was set at $200.0 million, and we had $184.0 million of debt outstanding under the facility, leaving us with $16.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of June 30, 2018. Our Credit Agreement matures on March 31, 2020.

Open Commodity Hedge Positions

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties. In August 2017, we repositioned certain of our crude oil and natural gas hedges in anticipation of the sale of the Texas Production Assets and, in the process, received $3.6 million in net cash from the counterparties on those hedges.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. All of our derivatives are currently collateralized by the assets securing our Credit Agreement and therefore currently do not require the posting of cash collateral. This is significant since we are able to lock in sales prices on a substantial amount of our expected future production without posting cash collateral based on price changes prior to the hedges being cash settled.

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The following tables as of June 30, 2018, summarize, for the periods indicated, our hedges currently in place through December 31, 2020. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps— West Texas Intermediate (WTI)

	Three Months Ended (volume in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2018	—	$ —	—	$ —	62,840	$ 59.78	59,704	$ 59.84	122,544	$ 59.81
2019	62,528	$ 60.41	59,552	$ 60.44	57,024	$ 60.48	54,824	$ 60.52	233,928	$ 60.46
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50
									557,056	

MTM Fixed Price Basis Swaps– NYMEX (Henry Hub)

	Three Months Ended (volume in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2018	—	$ —	—	$ —	121,600	$ 3.00	117,040	$ 3.00	238,640	$ 3.00
2019	119,832	$ 2.85	115,784	$ 2.85	112,032	$ 2.85	108,552	$ 2.85	456,200	$ 2.85
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85
									1,097,288	

Operating Cash Flows

We had net cash flows provided by operating activities for the six months ended June 30, 2018 of $37.1 million, compared to net cash flow provided by operating activities of $23.4 million for the same period in 2017. This increase was primarily related to expedited collection of accounts receivable-related entities which lead to additional cash inflows of $6.6 million for the six months ended June 30, 2018 compared to the six months ended June 30, 2017. Further, operating cash flows increased as a result of higher average commodity process between the periods of $3.1 million, and a return from equity investment greater than equity earnings for the period of $3.6 million.

Our operating cash flows are subject to many variables, the most significant of which is the volume of oil and natural gas transported through our midstream assets, volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future operating cash flows will depend on oil and natural gas transported through our midstream assets, as well as the market prices of oil and natural gas and our hedging program.

Investing Activities

We had net cash flows provided by investing activities for the six months ended June 30, 2018 of $1.3 million, consisting primarily of $5.9 million related to proceeds from the sale of oil and natural gas properties, $1.7 million related to midstream activities, including pipeline construction, and $2.7 million related to the purchase of equity investments.

We had net cash flows used in investing activities for the six months ended June 30, 2017 of $22.3 million, consisting of $13.8 million related to pipeline construction and contributions to Carnero Processing and Carnero Gathering totaling $8.5 million.

Financing Activities

Net cash flows used in financing activities was $36.2 million for the six months ended June 30, 2018. During the six months ended June 30, 2018, we distributed $17.5 million and $13.6 million to Class B Preferred Unit holders and common unit holders, respectively, during the same period. Additionally, we paid $0.1 million in offering costs and repaid borrowings of $5.0 million.

Net cash flows used in financing activities was $0.1 million for the six months ended June 30, 2017. During the six months ended June 30, 2017, we had borrowings under our Credit Agreement of $25.0 million. We distributed $14.0 million and $12.0 million to Class B Preferred Unit holders and common unit holders, respectively, during the same period. Additionally, we paid $0.3 million in offering costs and received $1.3 million in proceeds from issuance of common units.

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Off-Balance Sheet Arrangements

As of June 30, 2018, we had no off-balance sheet arrangements with third parties, and we maintained no debt obligations that contained provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through June 30, 2018, we have not suffered any significant losses with our counterparties as a result of non-performance.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of 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 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.

As of June 30, 2018, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017, which was filed with the SEC on March 12, 2018. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read Part 1. Item 1. Note 2. “Basis of Presentation and Summary of Significant Accounting Policies” to the condensed consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

See Part 1. Item 1. Note 2. “Basis of Presentation and Summary of Significant Accounting Policies” to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

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

A significant market risk exposure is in the pricing that we receive for our crude oil, natural gas and NGL production. Realized pricing is primarily driven by the prevailing market prices applicable to our crude oil, natural gas and NGL production. Pricing for crude 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 crude 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 the Organization of Petroleum Exporting Countries.

To reduce the impact of crude oil and natural gas price volatility on our operations, the Partnership periodically enters into derivative contracts with respect to a portion of its projected crude 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 Partnership 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 Partnership 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 Partnership receives the excess, if

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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 Partnership may periodically enter 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 Credit Agreement, are intended to support crude 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 financial institutions deemed by management as competent and competitive market makers. All of our derivatives are currently collateralized by the assets securing our Credit Agreement and therefore currently do not require the posting of cash collateral. It is never the Partnership's intention to enter into derivative contracts for speculative trading purposes.

The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon crude 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 crude 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. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

At June 30, 2018, the fair value of our commodity derivative contracts was a net liability of approximately $3.7 million. A 10% increase in the oil and natural gas index prices above the June 30, 2018 prices would result in a decrease in the fair value of our commodity derivative contracts of $3.8 million; conversely, a 10% decrease in the oil and natural gas index price would result in an increase of $3.8 million.

Interest Rate Risk

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) LIBOR plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) ABR plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus (iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date. As of June 30, 2018, there was $184.0 million in borrowings outstanding under the Credit Agreement.

As of June 30, 2018, 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 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

The Principal Executive Officer and the Principal Financial Officer of the general partner of SNMP have evaluated the effectiveness of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of June 30, 2018 (the “Evaluation Date”). Based on such evaluation, the Principal Executive Officer and the Principal Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and is accumulated and communicated to our management, including the Principal Executive Officer and the Principal Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The adoption of ASC 606, Revenue from Contracts with Customers, required the

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implementation of new controls and the modification of certain accounting processes related to revenue recognition. The impact of these changes was not material to our internal control over financial reporting.

Part II—Other Information

Item 1. Legal Proceedings

From time to time we may be the subject of lawsuits and claims arising in the ordinary course of business. Management cannot predict the ultimate outcome of such lawsuits or claims. Management does not currently expect the outcome of any of the known claims or proceedings to individually or in the aggregate have a material adverse effect on our results of operations or financial condition.

Item 1A. Risk Factors

Consider carefully the risk factors under the caption “Risk Factors” under Part I, Item 1A in our 2017 Annual Report on Form 10-K, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2017 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

No common units were purchased in the second quarter of 2018, and none have been issued in the second quarter of 2018 that have not previously been reported on a Form 8-K.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the exhibit index below and are incorporated herein by reference.

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EXHIBIT INDEX

Exhibit Number	Description
2.1*,+	Agreement to Purchase Oil and Gas Interests between SEP Holdings IV, LLC and EP Energy E&P Company, L.P., dated April 30, 2018.
10.1	Eighth Amendment to the Third Amended and Restated Credit Agreement dated as of May 7, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners on May 10, 2018, File No. 001-33147).
31.1*	Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*Filed herewith.

**Furnished herewith.

+The exhibits to the Agreement to Purchase Oil and Gas Interests have been omitted pursuant to Item 601(b)(2) of Regulation S- K. The Partnership will furnish copies of such omitted exhibits to the Securities and Exchange Commission upon request. Descriptions of such exhibits are set forth within the body of the Agreement to Purchase Oil and Gas Interests.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, Sanchez Midstream Partners LP, the Registrant, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SANCHEZ MIDSTREAM PARTNERS LP

(REGISTRANT)

By: Sanchez Midstream Partners GP LLC, its general partner

Date: August 9, 2018 By /s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer and Secretary

(Duly Authorized Officer and Principal Financial Officer)