Table of Contents

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, 2019

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 **(State or Other Jurisdiction of Incorporation or Organization)**	**11-3742489** **(I.R.S. Employer Identification No.)**
1000 Main Street, Suite 3000 **Houston, Texas** **(Address of Principal Executive Offices)**	**77002** **(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)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark 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 ☐	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 ☒

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units representing limited partner interests	SNMP	NYSE American

Common units outstanding as of August 8, 2019: Approximately 20,089,827 units.

TABLE OF CONTENTS

		Page
PART I—Financial Information		6
Item 1.	Financial Statements	6
	Condensed Consolidated Statements of Operations (Unaudited)	6
	Condensed Consolidated Balance Sheets (Unaudited)	7
	Condensed Consolidated Statements of Cash Flows (Unaudited)	8
	Condensed Consolidated Statements of Changes in Partners' Capital (Unaudited)	9
	Notes to Condensed Consolidated Financial Statements (Unaudited)	10
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	28
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	41
Item 4.	Controls and Procedures	42
PART II—Other Information		42
Item 1.	Legal Proceedings	42
Item 1A.	Risk Factors	42
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	42
Item 3.	Defaults Upon Senior Securities	42
Item 4.	Mine Safety Disclosures	42
Item 5.	Other Information	42
Item 6.	Exhibits	42
Signatures		44

Cautionary Note Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q (this "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; 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; our future operating results; 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 Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Part I, Item 2. and other items within this 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," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this 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;
- 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 creditworthiness and performance of our counterparties, including financial institutions, operating partners, customers and other counterparties;
- our ability to grow enterprise value;
- 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 the Services Agreement (as defined below);
- Manager's ability to retain personnel to perform its obligations under its shared services agreement with SOG;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;
- the 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;
- 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 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 Form 10-Q and in our other public filings with the SEC.

Management cautions all readers that the forward-looking statements contained in this 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.

COMMONLY USED DEFINED TERMS

As used in this 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 entity in which we have a 50% or greater ownership interest.
- “Bbl” means one barrel of 42 U.S. gallons of oil.
- “Board” means the board of directors of our general partner.
- “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.
- “Manager” refers to SP Holdings, LLC, the sole member of our general partner.
- “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 (OTC Pink: SNEC) and its consolidated subsidiaries.
- “SOG” refers to Sanchez Oil & Gas Corporation, an entity that provides operational support to us.

Table of Contents

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,	
	2019	2018	2019	2018
Revenues				
Natural gas sales	$ 256	$ 226	$ 366	$ 699
Oil sales	3,811	1,584	3,072	5,046
Natural gas liquid sales	117	400	296	995
Gathering and transportation sales	1,702	1,661	3,385	3,349
Gathering and transportation lease revenues	15,969	13,168	32,226	25,486
Total revenues	21,855	17,039	39,345	35,575
Expenses				
Operating expenses				
Lease operating expenses	2,065	2,007	3,780	3,978
Transportation operating expenses	3,048	3,071	5,724	5,918
Production taxes	141	287	324	609
General and administrative expenses	4,171	6,919	8,920	12,084
Unit-based compensation expense	175	1,347	810	2,785
Gain on sale of assets	—	(2,388)	—	(2,388)
Depreciation, depletion and amortization	6,174	6,545	12,603	13,173
Accretion expense	126	123	259	249
Total operating expenses	15,900	17,911	32,420	36,408
Other (income) expense				
Interest expense, net	2,814	2,780	5,600	5,379
Earnings from equity investments	(791)	(3,111)	(2,233)	(7,383)
Other (income) expense	(21)	1,254	(67)	1,524
Total other (income) expenses	2,002	923	3,300	(480)
Total expenses	17,902	18,834	35,720	35,928
Income (loss) before income taxes	3,953	(1,795)	3,625	(353)
Income tax expense	76	—	122	—
Net income (loss)	3,877	(1,795)	3,503	(353)
Less				
Preferred unit paid-in-kind distributions	(10,605)	(3,500)	(10,605)	(3,500)
Preferred unit distributions	—	(7,000)	(8,838)	(15,750)
Preferred unit amortization	(745)	(568)	(1,442)	(1,099)
Net loss attributable to common unitholders	$ (7,473)	$ (12,863)	$ (17,382)	$ (20,702)
Net loss per unit				
Common units - Basic and Diluted	$ (0.42)	$ (0.85)	$ (1.02)	$ (1.38)
Weighted Average Units Outstanding				
Common units - Basic and Diluted	17,684,563	15,199,779	16,968,736	14,997,058

See accompanying notes to condensed consolidated financial statements.

Table of Contents

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	June 30, 2019	December 31, 2018
ASSETS	(Unaudited)	
Current assets		
Cash and cash equivalents	$ 1,253	$ 2,934
Accounts receivable	167	277
Accounts receivable - related entities	6,520	6,700
Prepaid expenses	1,432	931
Fair value of commodity derivative instruments	661	3,044
Total current assets	10,033	13,886
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	112,449	112,173
Gathering and transportation assets	186,845	186,406
Less: accumulated depreciation, depletion, amortization and impairment	(106,094)	(100,245)
Oil and natural gas properties and equipment, net	193,200	198,334
Other assets		
Intangible assets, net	151,976	158,706
Fair value of commodity derivative instruments	59	876
Equity investments	108,776	114,465
Other non-current assets	352	418
Total assets	$ 464,396	$ 486,685
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 3,964	$ 4,678
Accounts payable and accrued liabilities - related entities	5,821	5,641
Royalties payable	359	359
Short-term debt, net of debt issuance costs	171,153	—
Fair value of commodity derivative instruments	541	6
Other liabilities	139	125
Total current liabilities	181,977	10,809
Other liabilities		
Asset retirement obligation	6,631	6,200
Long-term debt, net of debt issuance costs	—	178,582
Fair value of commodity derivative instruments	157	—
Other liabilities	5,802	5,857
Total other liabilities	12,590	190,639
Total liabilities	194,567	201,448
Commitments and contingencies (See Note 12)		
Mezzanine equity		
Class B preferred units, 31,310,896 units issued and outstanding as of June 30, 2019 and December 31, 2018	353,067	349,857
Partners' deficit		
Common units, 19,188,086 and 16,486,239 units issued and outstanding as of June 30, 2019 and December 31, 2018, respectively	(83,238)	(64,620)
Total partners' deficit	(83,238)	(64,620)
Total liabilities and partners' capital	$ 464,396	$ 486,685

See accompanying notes to condensed consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES
Condensed Consolidated Statements of Cash Flows
(In thousands)
(unaudited)

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Cash flows from operating activities:		
Net income (loss)	$ 3,503	$ (353)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	5,873	6,443
Amortization of debt issuance costs	578	265
Accretion expense	259	249
Distributions from equity investments	8,164	13,101
Equity earnings in affiliate	(2,233)	(7,383)
Gain on sale of assets	—	(2,388)
Net loss on commodity derivative contracts	3,524	5,653
Net cash settlements received (paid) on commodity derivative contracts	469	(706)
Unit-based compensation	810	2,785
(Gain) loss on earnout derivative	(63)	1,524
Amortization of intangible assets	6,730	6,730
Changes in Operating Assets and Liabilities:		
Accounts receivable	23	185
Accounts receivable - related entities	176	6,541
Prepaid expenses	(501)	83
Other assets	42	43
Accounts payable and accrued liabilities	2,585	7,687
Accounts payable and accrued liabilities- related entities	176	(3,376)
Other long-term liabilities	22	(1)
Net cash provided by operating activities	30,137	37,082
Cash flows from investing activities:		
Development of oil and natural gas properties	(103)	(205)
Proceeds from sale of assets	—	5,896
Construction of gathering and transportation assets	(357)	(1,700)
Purchases of and contributions to equity affiliates	(242)	(2,713)
Net cash provided by (used in) investing activities	(702)	1,278
Cash flows from financing activities:		
Payments for offering costs	—	(50)
Repayment of debt	(8,000)	(5,000)
Distributions to common unitholders	(5,216)	(13,614)
Class B preferred unit cash distributions	(17,675)	(17,500)
Units tendered by SOG employees for tax withholdings	(218)	—
Debt issuance costs	(7)	(33)
Net cash used in financing activities	(31,116)	(36,197)
Net increase (decrease) in cash and cash equivalents	(1,681)	2,163
Cash and cash equivalents, beginning of period	2,934	321
Cash and cash equivalents, end of period	$ 1,253	$ 2,484
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 82	$ 341
Cash paid during the period for interest	$ 5,070	$ 4,788

See accompanying notes to condensed consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Partners’ Capital

(In thousands, except unit data)

(Unaudited)

	Common Units		Total
	Units	Amount	Capital
Partners' Deficit, December 31, 2018	16,486,239	$ (64,620)	$ (64,620)
Adoption of accounting standards	—	(181)	(181)
Unit-based compensation programs	978,076	815	815
Issuance of common units	787,750	1,355	1,355
Cash distributions to common unitholders	—	(2,471)	(2,471)
Distributions - Class B preferred units	—	(9,535)	(9,535)
Net loss	—	(374)	(374)
Partners' Deficit, March 31, 2019	18,252,065	$ (75,011)	$ (75,011)
Unit-based compensation programs	133,463	175	175
Units tendered by SOG employees for tax withholdings	(84,711)	(218)	(218)
Issuance of common units	887,269	2,034	2,034
Cash distributions to common unitholders	—	(2,745)	(2,745)
Distributions - Class B preferred units	—	(11,350)	(11,350)
Net income	—	3,877	3,877
Partners' Deficit, June 30, 2019	19,188,086	$ (83,238)	$ (83,238)

	Common Units		Total
	Units	Amount	Capital
Partners' Capital, December 31, 2017	14,965,134	$ (29,308)	$ (29,308)
Unit-based compensation programs	(4,166)	738	738
Issuance of common units, net of offering costs of $0.1 million	210,978	2,292	2,292
Cash distributions to common unitholders	—	(6,746)	(6,746)
Distributions - Class B preferred units	—	(9,281)	(9,281)
Net income	—	1,442	1,442
Partners' Deficit, March 31, 2018	15,171,946	$ (40,863)	$ (40,863)
Unit-based compensation programs	608,394	2,047	2,047
Issuance of common units, net of offering costs of $0.1 million	220,214	2,280	2,280
Cash distributions to common unitholders	—	(6,868)	(6,868)
Distributions - Class B preferred units	—	(11,068)	(11,068)
Net loss	—	(1,795)	(1,795)
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. We have ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, 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 Manager, pursuant to which Manager provides services we require to conduct our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services. On June 2, 2017, we changed our name to Sanchez Midstream Partners LP from Sanchez Production Partners LP. Manager owns our general partner and all of our 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 ("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. Our business consists of two reportable segments: Production and Midstream. Our Midstream segment includes Western Catarina Midstream (defined in Note 10 "Intangible Assets"), the Carnero JV (defined in Note 11 "Investments") and Seco Pipeline. Our Production segment consists of our oil and natural gas properties in Texas and Louisiana. 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 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 our audited consolidated financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2018, which was filed with the SEC on March 7, 2019.

Recent Accounting Pronouncements

In August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2018-13 "Fair Value Measurement (ASC 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements," which modifies the disclosure requirements on fair value measurements. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In June 2018, the FASB issued 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. We adopted this ASU effective January 1, 2019, which resulted in the remeasurement of our outstanding unvested awards as of January 1, 2019 and will change the expense recorded for equity awards going forward. The adoption of this standard resulted in an approximately $0.2 million charge to retained earnings.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in more timely recognition of losses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019, and earlier adoption is permitted. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

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. 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 Partnership elected the practical expedients disclosed in ASU 2018-10. The effective date in ASU 2018-10 is the same as that of ASU 2016-02. The standards update the previous lease guidance by requiring the recognition of a right-of-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 adopted this standard effective January 1, 2019. The adoption of this standard did not have a material impact on our condensed consolidated financial statements.

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 GAAP, which requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and accompanying notes therein. 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.

3. REVENUE RECOGNITION

Revenue from Contracts with Customers

We account for revenue from contracts with customers in accordance with ASC 606. The unit of account in ASC 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. ASC 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 the only contract that we account for under ASC 606. The Catarina Midstream Gathering Agreement is classified as an operating lease and is accounted for under ASC 842, Leases, and is reported as gathering and transportation lease revenue in our condensed consolidated statements 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 ASC 606.

We recognized aggregate revenue of $21.9 million for the three months ended June 30, 2019. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Three Months Ended June 30, 2019		
	Production	**Midstream**	**Total**
Revenues:			
Natural gas sales	$ 256	$ —	$ 256
Oil sales	3,811	—	3,811
Natural gas liquid sales	117	—	117
Gathering and transportation sales	—	1,702	1,702
Gathering and transportation lease revenues	—	15,969	15,969
Total revenues	$ 4,184	$ 17,671	$ 21,855

We recognized aggregate revenue of $39.3 million for the six months ended June 30, 2019. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Six Months Ended June 30, 2019		
	Production	**Midstream**	**Total**
Revenues:			
Natural gas sales	$ 366	$ —	$ 366
Oil sales	3,072	—	3,072
Natural gas liquid sales	296	—	296
Gathering and transportation sales	—	3,385	3,385
Gathering and transportation lease revenues	—	32,226	32,226
Total revenues	$ 3,734	$ 35,611	$ 39,345

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 which is available only for wholly unsatisfied performance obligations for which the criteria in ASC 606 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 condensed 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 performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At each of June 30, 2019 and December 31, 2018, our receivables from contracts with customers were $0.6 million and are presented within accounts receivable – related entities on the condensed consolidated balance sheets.

4. ACQUISITIONS AND DIVESTITURES

Louisiana Divestiture

In September 2018, we entered into a purchase and sale agreement to sell certain non-operated production assets located in Louisiana for cash consideration of approximately $1.3 million (the "Louisiana Divestiture"). The Louisiana Divestiture closed on October 22, 2018, and we recorded a gain of approximately $0.6 million on the sale.

Briggs Divestiture

In April 2018, we entered into a purchase and sale agreement to sell specified wellbores and related assets and interests in La Salle County Texas (the "Briggs Assets") for cash consideration of approximately $4.2 million (the "Briggs Divestiture"). In addition, other than limited obligations that we retained, the buyer of the Briggs Assets 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 $1.8 million on the sale.

Cola Divestiture

In April 2018, we entered into multiple purchase and sale agreements to sell certain non-operated production assets located in Oklahoma for total cash consideration of approximately $1.0 million (collectively, the "Cola Divestiture"). Each of the divestitures closed by May 8, 2018, and we recorded a total gain of approximately $1.1 million on the sales.

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, 2019 (in thousands):

	Fair Value Measurements at June 30, 2019			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative assets	$ —	$ 22	$ —	$ 22
Midstream derivative instrument				
Earnout derivative liability	—	—	(5,793)	(5,793)
Total	$ —	$ 22	$ (5,793)	$ (5,771)

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, 2018 (in thousands):

	Fair Value Measurements at December 31, 2018			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative assets	$ —	$ 3,914	$ —	$ 3,914
Midstream derivative instrument				
Earnout derivative liability	—	—	(5,856)	(5,856)
Total	$ —	$ 3,914	$ (5,856)	$ (1,942)

As of June 30, 2019 and December 31, 2018, 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 market and therefore represent Level 3 inputs under the fair value hierarchy. We periodically review oil and natural gas properties and related equipment 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."

We had no non-recurring fair value measurements of our assets as of June 30, 2019 and December 31, 2018.

The fair values of oil and natural gas properties and related equipment 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 and related equipment include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; (v) estimated throughput; and (vi) 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

The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below. 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.

Credit Agreement – We believe that the carrying value of 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. The 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, 2019.

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 the earnout derivative as Level 3 and is presented within other liabilities on the condensed consolidated balance sheets.

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

	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Beginning balance	$ (5,856)	$ (6,402)
Gain on earnout derivative	63	546
Ending balance	$ (5,793)	$ (5,856)
Gain included in earnings related to derivatives still held as of June 30, 2019 and December 31, 2018, respectively	$ 63	$ 546

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, 2019, 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
2019	—	$ —	—	$ —	57,024	$ 60.48	54,824	$ 60.52	111,848	$ 60.50
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50
									312,432	

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
2019	—	$ —	—	$ —	112,032	$ 2.85	108,552	$ 2.85	220,584	$ 2.85
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85
									623,032	

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, 2019 and the year ended December 31, 2018 (in thousands):

	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Beginning fair value of commodity derivatives	$ 3,914	$ 1,231
Net gains (losses) on crude oil derivatives	(3,677)	1,400
Net gains (losses) on natural gas derivatives	153	(84)
Net settlements paid (received) on derivative contracts:		
Oil	(381)	1,330
Natural gas	13	37
Ending fair value of commodity derivatives	$ 22	$ 3,914

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

Derivative Type	Location of Gain (Loss) in Income	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Commodity – Mark-to-Market	Oil sales	$ 807	$ (3,717)	$ (3,677)	$ (5,657)
Commodity – Mark-to-Market	Natural gas sales	193	2	153	4
		$ 1,000	$ (3,715)	$ (3,524)	$ (5,653)

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with three 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. As of June 30, 2019 and December 31, 2018, 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 ("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 us, certain of our subsidiaries and the administrative agent.

Our Credit Agreement is a current liability that matures on March 31, 2020. We expect to refinance or extend the maturity of our Credit Agreement prior to its maturity date. However, we may not be able to refinance or extend the maturity of our Credit Agreement or, if we are able to refinance or extend the maturity, we may not be able to do so with borrowing and debt issue costs, terms, covenants, restrictions, commitment amount or a borrowing base favorable to us.

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 the 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, 2019, the borrowing base under the Credit Agreement was $303.1 million, with an elected commitment amount of $210.0 million, and we had $172.0 million of debt outstanding under the facility, leaving us with $38.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of June 30, 2019.

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 ratio of at least 1.0 to 1.0 at all times;
- senior secured net debt to consolidated Adjusted EBITDA ratio 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 for the proper conduct of our business and the payment of fees and expenses.

At June 30, 2019, 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 under the Credit Agreement 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, 2019 and December 31, 2018, our unamortized debt issuance costs were $0.8 million and $1.4 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 the three months ended June 30, 2019 and 2018 was $0.3 million and $0.1 million, respectively. Amortization of debt issuance costs recorded during the six months ended June 30, 2019 and 2018 was $0.6 million and $0.3 million, respectively.

8. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

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

	June 30, 2019	December 31, 2018
Gathering and transportation assets		
Midstream assets	$ 186,845	$ 186,406
Less: Accumulated depreciation and amortization	(38,549)	(34,598)
Total gathering and transportation assets, net	$ 148,296	$ 151,808

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

	June 30, 2019	December 31, 2018
Oil and natural gas properties and related equipment		
Proved property	$ 112,449	$ 112,173
Less: Accumulated depreciation, depletion, amortization and impairments	(67,545)	(65,647)
Total oil and natural gas properties and equipment, net	$ 44,904	$ 46,526

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 and amortization consisted of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 828	$ 1,251	$ 1,923	$ 2,614
Depreciation and amortization of gathering and transportation related assets	1,981	1,929	3,950	3,829
Amortization of intangible assets	3,365	3,365	6,730	6,730
Total Depreciation, depletion and amortization	$ 6,174	$ 6,545	$ 12,603	$ 13,173

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 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 each of the three and six months ended June 30, 2019 and 2018, we recorded no impairment charges.

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 properties, equipment and facilities or gathering and transportation assets.

The following table is a reconciliation of changes in ARO for the six months ended June 30, 2019 and the year ended December 31, 2018 (in thousands):

	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Asset retirement obligation, beginning balance	$ 6,200	$ 6,074
Liabilities added from escalating working interests	172	288
Sales	—	(613)
Revisions to cost estimates	—	(46)
Accretion expense	259	497
Asset retirement obligation, ending balance	$ 6,631	$ 6,200

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, 2019 and the year ended December 31, 2018, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs. During the year ended December 31, 2018, obligations were sold as part of the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

10. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes $152.0 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 area 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 each of the six months ended June 30, 2019 and 2018 was approximately $6.7 million. These costs are amortized to depreciation, depletion, and amortization expense in our condensed consolidated statements of operations. The following table is a reconciliation of changes in intangible assets (in thousands):

	June 30, 2019	December 31, 2018
Beginning balance	$ 158,706	$ 172,166
Amortization	(6,730)	(13,460)
Ending balance	$ 151,976	$ 158,706

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 in our 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 and other parties 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 within Carnero G&P, LLC (the “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 the Carnero JV, which expands the processing capacity of the Carnero JV from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the 45 miles of high pressure natural gas gathering pipelines owned by Carnero Gathering that connect Western Catarina Midstream to nearby pipelines and the Raptor Gas Processing Facility (the “Carnero Gathering Line”) to the Carnero JV resulting in the Carnero JV owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) the Carnero JV received a new dedication from Sanchez Energy and its working interest partners of over 315,000 Comanche acres in the Western Eagle Ford pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the Carnero JV limited by the capacity of the Raptor Gas Processing Facility. As a result of the Carnero JV Transaction, we now record our share of earnings and losses from the Carnero JV using the Hypothetical Liquidation at Book Value (“HLBV”) method of accounting. The HLBV is a balance-sheet approach that calculates the amount we would have received if the 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 the 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, 2019, the Partnership had paid approximately $124.1 million for its investment in the 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 Carnero JV 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 sheets. For the three months ended June 30, 2019, the Partnership recorded earnings of approximately $1.1 million in equity investments from the 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, 2019, the Partnership recorded earnings of approximately $2.8 million in equity investments from the 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 earnings from equity investments within the condensed consolidated statements of operations. Cash distributions of approximately $8.2 million were received during the six months ended June 30, 2019.

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

	Six Months Ended June 30,	
	2019	2018
Sales	$ 97,061	$ 179,798
Total expenses	88,647	163,091
Net income	$ 8,414	$ 16,707

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 $5.8 million and is recorded as other liabilities on our condensed consolidated balance sheet. For the six months ended June 30, 2019, we paid Sanchez Energy $32.1 thousand related to the earnout. For the six months ended June 30, 2018, the natural gas the Carnero JV received did not exceed the aforementioned threshold, which resulted in no payment to Sanchez Energy related to the earnout.

13. RELATED PARTY TRANSACTIONS

Please read the disclosure under the headings “Sanchez-Related Agreements” and “Sanchez-Related Transactions” in Note 14 “Related Party Transactions” of our Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018 for a more complete description of certain related party transactions that were entered into prior to 2019. The following is an update to such disclosure:

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”). 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. Subsequent to the conclusion of the incremental infrastructure fee amendment, the parties have agreed to continue the incremental infrastructure fee on a month-to-month basis. On January 1, 2019 and April 1, 2019, the Partnership increased the Western Catarina Midstream tariff rate for throughput volumes which are outside of the dedicated acreage under the Gathering Agreement.

As of June 30, 2019 and December 31, 2018, the Partnership had a net receivable from related parties of approximately $6.5 million, and $6.7 million, respectively, which are included in accounts receivable – related entities on the condensed consolidated balance sheets. As of June 30, 2019 and December 31, 2018, the Partnership also had a net payable to related parties of approximately $5.8 million, and $5.6 million, respectively, which are included in accounts payable – related entities on the condensed consolidated balance sheets. The net receivable/payable as of June 30, 2019 and December 31, 2018 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.

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, 2018	513,694	$ 12.31
Granted	1,129,173	2.35
Vested	(381,729)	8.49
Returned/Cancelled	(102,345)	12.05
Outstanding at June 30, 2019	1,158,793	$ 3.88

In April 2019, the Partnership issued 137,613 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 March 2019, the Partnership issued 991,560 restricted common units pursuant to the LTIP to certain officers and directors of the Partnership's general partner that vest over three years from the date of grant. The unit based compensation expense for the awards was based on the fair value on the day before the grant date.

As of June 30, 2019, 703,185 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, 2019 and each of the three month periods ended during the year ended December 31, 2018.

Three months ended		Distribution per unit	Date of declaration	Date of record	Date of distribution
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
September 30, 2018	$	0.1500	November 9, 2018	November 20, 2018	November 30, 2018
December 31, 2018	$	0.1500	February 7, 2019	February 20, 2019	February 28, 2019
March 31, 2019	$	0.1500	May 3, 2019	May 22, 2019	May 31, 2019
June 30, 2019 [(a)]	$	—	August 8, 2019	—	—

(a) In connection with the second-quarter 2019 distribution, the Board determined to establish a cash reserve to pay down a portion of the Partnership's debt outstanding under the Credit Agreement. Following the establishment of the cash reserve, the Board determined that the Partnership did not have any available cash and, as a result, no cash distribution was declared for the common units with respect to the second-quarter 2019. See Note 19 "Subsequent Events."

The table below reflects the payment of distributions on Class B Preferred Units (defined below) related to the six months ended June 30, 2019 and each of the three month periods ended during the year ended December 31, 2018.

Three months ended		Cash distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2018	$	0.28225	May 8, 2018	May 22, 2018	May 31, 2018
June 30, 2018 [(a)]	$	0.22580	August 8, 2018	August 21, 2018	August 31, 2018
September 30, 2018	$	0.28225	November 9, 2018	November 20, 2018	November 30, 2018
December 31, 2018	$	0.28225	February 7, 2019	February 20, 2019	February 28, 2019
March 31, 2019	$	0.28225	May 3, 2019	May 22, 2019	May 31, 2019
June 30, 2019 [(b)]	$	—	—	—	—

(a) 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 PIK Units. Accordingly, the Partnership declared a cash distribution of $0.22580 per Class B Preferred Unit and an aggregate distribution of 310,009 Class B Preferred PIK Units, each distribution was paid on August 31, 2018 to holders of record on August 21, 2018.

(b) On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units (the "Class C Preferred Units"). As a result, no distribution was declared with respect to the Class B Preferred Units. See Note 19 "Subsequent Events."

The table below reflects the payment of distributions on Class C Preferred Units related to the three months ended June 30, 2019.

Three months ended		Cash distribution per unit	Date of declaration	Date of record	Date of distribution
June 30, 2019 [(a)]	$	—	August 8, 2019	August 20, 2019	August 30, 2019

(a) The Board determined that the Partnership did not have any available cash with respect to the second-quarter 2019 and, as a result, the Amended Partnership Agreement (defined below) requires that the Partnership pay the second-quarter 2019 distribution on the Class C Preferred Units 100% in Class C Preferred PIK Units. Accordingly, the Partnership declared an aggregate distribution of 939,327 Class C Preferred PIK Units, payable on August 30, 2019 to holders of record on August 20, 2019. See Note 19 "Subsequent Events."

16. PARTNERS' CAPITAL

Outstanding Units

As of June 30, 2019, we had 31,310,896 Class B Preferred Units outstanding, and 19,188,086 common units outstanding, which included 1,158,793 unvested restricted common units issued under the LTIP.

Common Unit Issuances

The following table shows the common units issued by the Partnership in 2018 and 2019 to Manager in connection with providing services under the Services Agreement:

Three months ended	Common units	Date of issuance
December 31, 2017	210,978	March 15, 2018
March 31, 2018	220,214	May 31, 2018
June 30, 2018	224,342	September 10, 2018
September 30, 2018	334,010	November 30, 2018
December 31, 2018	787,750	March 8, 2019
March 31, 2019	887,269	May 23, 2019

Class B Preferred Unit Offering

On October 14, 2015, pursuant to the 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 the Second Amended and Restated Agreement of Limited Partnership of the Partnership (as amended by Amendment No. 1 and Amendment No. 2 thereto, the "Second Partnership Agreement"), holders of the Class B Preferred Units receive a quarterly distribution, at the election of the Board, of 10.0% per annum if paid in full in cash or 12.0% per annum if paid in part cash (8.0% per annum) and in part Class B Preferred PIK Units (4.0% per annum), as defined in the Second Partnership Agreement. 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 Second Partnership Agreement, on December 6, 2016 the Partnership 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 Partnership Agreement. Pursuant to the Settlement Agreement, and in accordance with Section 5.4 of the Second 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 Second 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 Partnership elected to pay the second-quarter 2018 distribution on the Class B Preferred Units in part cash and part Class B Preferred PIK Units in accordance with the Second Partnership Agreement. Accordingly, the Partnership issued 310,009 Class B Preferred PIK Units on August 31, 2018, to Stonepeak.

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

	June 30, 2019	December 31, 2018
Mezzanine equity, beginning balance	$ 349,857	$ 343,912
Amortization of discount	1,442	2,358
Distributions	19,443	36,925
Distributions paid	(17,675)	(33,338)
Mezzanine equity, ending balance	$ 353,067	$ 349,857

On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and a warrant exercisable for junior securities (the "Warrant"). See Note 19 "Subsequent Events."

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 Second 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 Second 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 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 Second 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.

The Partnership's 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.

The following tables present financial information for each operating segment for the periods indicated based on our operating segments (in thousands):

	Three Months Ended June 30,			
	2019		2018	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 256	$ —	$ 226	$ —
Oil sales	3,811	—	1,584	—
Natural gas liquid sales	117	—	400	—
Gathering and transportation sales	—	1,702	—	1,661
Gathering and transportation lease revenues	—	15,969	—	13,168
Total segment revenues	4,184	17,671	2,210	14,829
Segment operating costs				
Lease operating expenses	1,688	377	1,644	363
Transportation operating expenses	—	3,048	—	3,071
Production taxes	141	—	287	—
Gain on sale of assets	—	—	(2,388)	—
Depreciation, depletion and amortization	828	5,346	1,251	5,294
Accretion expense	46	80	49	74
Total segment operating costs	2,703	8,851	843	8,802
Segment other income				
Earnings from equity investments	—	791	—	3,111
Total segment other income	—	791	—	3,111
Segment operating income	$ 1,481	$ 9,611	$ 1,367	$ 9,138

	Six Months Ended June 30,			
	2019		2018	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 366	$ —	$ 699	$ —
Oil sales	3,072	—	5,046	—
Natural gas liquid sales	296	—	995	—
Gathering and transportation sales	—	3,385	—	3,349
Gathering and transportation lease revenues	—	32,226	—	25,486
Total segment revenues	3,734	35,611	6,740	28,835
Segment operating costs				
Lease operating expenses	3,007	773	3,396	582
Transportation operating expenses	—	5,724	—	5,918
Production taxes	324	—	609	—
Gain on sale of assets	—	—	(2,388)	—
Depreciation, depletion and amortization	1,923	10,680	2,614	10,559
Accretion expense	100	159	103	146
Total segment operating costs	5,354	17,336	4,334	17,205
Segment other income				
Earnings from equity investments	—	2,233	—	7,383
Total segment other income	—	2,233	—	7,383
Segment operating income (loss)	$ (1,620)	$ 20,508	$ 2,406	$ 19,013

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Reconciliation of segment operating income (loss) to net income (loss)				
Total production operating income (loss)	$ 1,481	$ 1,367	$ (1,620)	$ 2,406
Total midstream operating income	9,611	9,138	20,508	19,013
Total segment operating income	11,092	10,505	18,888	21,419
General and administrative expense	(4,171)	(6,919)	(8,920)	(12,084)
Unit-based compensation expense	(175)	(1,347)	(810)	(2,785)
Interest expense, net	(2,814)	(2,780)	(5,600)	(5,379)
Other income (expense)	21	(1,254)	67	(1,524)
Income tax expense	(76)	—	(122)	—
Net income (loss)	$ 3,877	$ (1,795)	$ 3,503	$ (353)

The following table summarizes the total assets by operating segment as of June 30, 2019 and December 31, 2018 and total capital expenditures for the six months ended June 30, 2019 and the year ended December 31, 2018 (in thousands):

	June 30, 2019			
	Production	Midstream	Corporate [(a)]	Total
Other financial information				
Total assets	$ 48,162	$ 414,129	$ 2,105	$ 464,396
Capital expenditures[(b)]	$ 103	$ 679	$ —	$ 782

	December 31, 2018			
	Production	Midstream	Corporate [(a)]	Total
Other financial information				
Total assets	$ 53,556	$ 429,523	$ 3,606	$ 486,685
Capital expenditures[(b)]	$ 11	$ 4,856	$ —	$ 4,867

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

18. VARIABLE INTEREST ENTITIES

The Partnership's investment in the Carnero JV represents a variable interest entity ("VIE") that could expose the Partnership to losses. The amount of losses the Partnership could be exposed to from the Carnero JV is limited to the capital investment of approximately $108.8 million.

As of June 30, 2019, the Partnership had invested approximately $124.1 million in the Carnero JV and no debt has been incurred by the Carnero JV. We have included this VIE in other assets, equity investments 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, 2019 and December 31, 2018 (in thousands):

	June 30, 2019	December 31, 2018
Acquisitions, earnout and capital investments	$ 128,140	$ 127,899
Earnings in equity investments	25,378	23,144
Distributions received	(44,742)	(36,578)
Maximum exposure to loss	$ 108,776	$ 114,465

19. SUBSEQUENT EVENTS

On July 9, 2019, the Partnership received notification that, pursuant to the terms of the Credit Agreement, its lenders have completed both their quarterly review of the borrowing base for the Partnership's midstream assets (the "midstream component") and their semi-annual review of the borrowing base for the Partnership's oil and natural gas properties (the "RBL component"). Based on this review, the midstream component has been set at $262.0 million and the RBL component has been set at $20.0 million, resulting in a total borrowing base of $282.0 million.

On July 29, 2019, the Partnership paid $4.0 million in principal outstanding under the Credit Agreement resulting in debt outstanding of $168.0 million under the Credit Agreement as of that date.

On August 2, 2019, the Partnership's general partner entered into Executive Services Agreements with each of Gerald F. Willinger, Chief Executive Officer of the Partnership's general partner, and Charles C. Ward, Chief Financial Officer and Secretary of the Partnership's general partner (collectively, the "Executive Agreements"). The Executive Agreements were approved by the Board on August 2, 2019. Copies of the Executive Agreements are filed as exhibits to this Form 10-Q.

On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and a warrant exercisable for junior securities (the "Warrant") in a privately negotiated transaction (the "Exchange"). In connection with the Exchange, the Partnership entered into (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended Partnership Agreement) to set forth the terms of the Class C Preferred Units, (ii) the Amended and Restated Registration Rights Agreement with Stonepeak relating to the registered resale of common units issuable upon the exercise of the Warrant, and (iii) the Amended and Restated Board Representation and Standstill Agreement with Stonepeak . In addition, on August 2, 2019, the Partnership's general partner entered into Amendment No. 3 to its Limited Liability Company Agreement to provide certain changes necessary in connection with the Exchange.

On August 8, 2019, the Board declared that after establishing a cash reserve for the payment of certain amounts outstanding under the Credit Agreement, the Partnership did not have any available cash and, as a result, there would be no cash distribution on the Partnership's common units. As required by the Amended Partnership Agreement, the Board declared a second quarter distribution on the Class C Preferred Units payable 100% in Class C Preferred PIK Units. Accordingly, the Partnership declared an aggregate distribution of 939,327 Class C Preferred PIK Units, payable on August 30, 2019 to holders of record on August 20, 2019.

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. We have ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, 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 the 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, we changed our name to Sanchez Midstream Partners LP from Sanchez Production Partners LP. Manager owns our general partner and all of our 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 Sanchez Energy's Catarina Asset, which consists of approximately 106,000 net acres in Dimmit, La Salle and Webb counties, 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.

Non-GAAP Financial Measures—Adjusted EBITDA

To supplement our financial results and guidance presented in accordance with 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 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,	
	2019	2018	2019	2018
Net income (loss)	$ 3,877	$ (1,795)	$ 3,503	$ (353)
Adjusted by:				
Interest expense, net	2,814	2,780	5,600	5,379
Income tax expense	76	—	122	—
Depreciation, depletion and amortization	6,174	6,545	12,603	13,173
Accretion expense	126	123	259	249
Gain on sale of assets	—	(2,388)	—	(2,388)
Unit-based compensation expense	175	1,347	810	2,785
Unit-based asset management fees	1,839	2,647	3,871	4,926
Distributions in excess of equity earnings	3,412	2,360	5,476	4,197
(Gain) loss on mark-to-market activities	(974)	4,453	3,829	6,431
Acquisition and divestiture costs	—	1,529	—	1,780
Adjusted EBITDA	$ 17,519	$ 17,601	$ 36,073	$ 36,179

Significant Operational Factors

Throughput. The following table sets forth selected throughput data pertaining to the Midstream segment for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Western Catarina Midstream:				
Oil (MBbls/d)	11.5	12.0	12.9	11.7
Natural gas (MMcf/d)	137.8	155.4	147.5	153.6
Water (MBbls/d)	5.0	11.8	7.1	10.2
Seco Pipeline:				
Natural gas (MMcf/d)	0.2	52.6	3.8	60.3

Production. Our production for the three months ended June 30, 2019, was 66 MBoe, or an average of 725 Boe/d, compared to approximately 118 MBoe, or an average of 1,297 Boe/d, for the three months ended June 30, 2018. Our production for the six months ended June 30, 2019, was 151 MBoe, or an average of 834 Boe/d, compared to approximately 259 MBoe, or an average of 1,431 Boe/d, for the six months ended June 30, 2018.

Hedging Activities. For the three months ended June 30, 2019, the non-cash mark-to-market gain for our commodity derivatives was approximately $0.9 million, compared to a loss of $3.2 million for the same period in 2018. For the six months ended June 30, 2019, the non-cash mark-to-market loss for our commodity derivatives was approximately $3.9 million, compared to a loss of $4.9 million for the same period in 2018.

Recent Developments

On July 9, 2019, we received notification that, pursuant to the terms of the Credit Agreement, our lenders completed both their quarterly review of the borrowing base for our midstream assets (the "midstream component") and their semi-annual review of the borrowing base for our oil and natural gas properties (the "RBL component"). Based on this review, the midstream component has been set at $262.0 million and the RBL component has been set at $20.0 million, resulting in a total borrowing base of $282.0 million.

On July 29, 2019, we paid $4.0 million in principal outstanding under the Credit Agreement resulting in debt outstanding of $168.0 million under the Credit Agreement as of that date.

On August 2, 2019, our general partner entered into Executive Services Agreements with each of Gerald F. Willinger, Chief Executive Officer of our general partner, and Charles C. Ward, Chief Financial Officer and Secretary of our general partner (collectively, the "Executive Agreements"). The Executive Agreements were approved by the Board on August 2, 2019. Copies of the Executive Agreements are filed as exhibits to this Form 10-Q.

On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and a warrant exercisable for junior securities (the "Warrant") in a privately negotiated transaction (the "Exchange"). In connection with the Exchange, we entered into (i) the Third Amended and Restated Agreement of Limited Partnership (the "Amended Partnership Agreement) to set forth the terms of the Class C Preferred Units, (ii) the Amended and Restated Registration Rights Agreement with Stonepeak relating to the registered resale of common units issuable upon the exercise of the Warrant, and (iii) the Amended and Restated Board Representation and Standstill Agreement with Stonepeak. In addition, on August 2, 2019, our general partner entered into Amendment No. 3 to its Limited Liability Company Agreement to provide certain changes necessary in connection with the Exchange.

On August 8, 2019, the Board declared that after establishing a cash reserve for the payment of certain amounts outstanding under the Credit Agreement, we did not have any available cash and, as a result, there would be no cash distribution on our common units. As required by the Amended Partnership Agreement, the Board declared a second quarter distribution on the Class C Preferred Units payable 100% in Class C Preferred PIK Units. Accordingly, on August 8, 2019, we declared an aggregate distribution of 939,327 Class C Preferred PIK Units, payable on August 30, 2019 to holders of record on August 20, 2019.

Results of Operations by Segment

Three months ended June 30, 2019 compared to three months ended June 30, 2018

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):

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Variance	
Revenues:				
Gathering and transportation sales	$ 1,702	$ 1,661	$ 41	2%
Gathering and transportation lease revenues	15,969	13,168	2,801	21%
Total gathering and transportation sales	17,671	14,829	2,842	19%
Operating expenses:				
Lease operating expenses	377	363	14	4%
Transportation operating expenses	3,048	3,071	(23)	(1%)
Depreciation and amortization	5,346	5,294	52	1%
Accretion expense	80	74	6	8%
Total operating expenses	8,851	8,802	49	1%
Other income:				
Earnings from equity investments	791	3,111	(2,320)	(75%)
Operating income	$ 9,611	$ 9,138	$ 473	5%

Gathering and transportation sales. Gathering and transportation sales remained relatively consistent for the three months ended June 30, 2019 with no material change when compared to the same period in 2018. Gathering and transportation lease revenues increased approximately $2.8 million, or 21%, to approximately $16.0 million compared to approximately $13.2 million for the same period in 2018. This increase was primarily the result of an increase in the rate charged for natural gas transported on Western Catarina Midstream that was produced from outside the dedicated acreage under the Gathering Agreement.

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 pipeline integrity management expenses. Our transportation operating expenses remained consistent for the three months ended June 30, 2019 with no material change when compared to the same period in 2018.

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 remained consistent for the three months ended June 30, 2019 with no material change when compared to the same period in 2018.

Earnings from equity investments. Earnings from equity investments decreased approximately $2.3 million, or 75%, to approximately $0.8 million for the three months ended June 30, 2019, compared to approximately $3.1 million for the same period in 2018. This decrease was the result of higher ad valorem taxes due to the addition of Silver Oak II to the Carnero JV as well as lower throughput during the three months ended June 30, 2019.

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 average unit costs):

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Variance	
Revenues:				
Natural gas sales at market price	$ 63	$ 224	$ (161)	(72%)
Natural gas hedge settlements	24	26	(2)	(8%)
Natural gas mark-to-market activities	169	(24)	193	NM [(a)]
Natural gas total	256	226	30	13%
Oil sales at market price	3,004	5,301	(2,297)	(43%)
Oil hedge settlements	34	(542)	576	NM [(a)]
Oil mark-to-market activities	773	(3,175)	3,948	NM [(a)]
Oil total	3,811	1,584	2,227	NM [(a)]
NGL sales	117	400	(283)	(71%)
Total revenues	4,184	2,210	1,974	89%
Operating expenses:				
Lease operating expenses	1,688	1,644	44	3%
Production taxes	141	287	(146)	(51%)
Gain on sale of assets	—	(2,388)	2,388	NM [(a)]
Depreciation, depletion and amortization	828	1,251	(423)	(34%)
Accretion expense	46	49	(3)	(6%)
Total operating expenses	2,703	843	1,860	NM [(a)]
Operating income	$ 1,481	$ 1,367	$ 114	8%

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

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Variance	
Net production:				
Natural gas (MMcf)	45	124	(79)	(64%)
Oil production (MBbl)	49	79	(30)	(38%)
NGLs (MBbl)	9	18	(9)	(50%)
Total production (MBoe)	66	118	(52)	(44%)
Average daily production (Boe/d)	725	1,297	(572)	(44%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 1.93	$ 2.02	$ (0.09)	(4%)
Natural gas price per Mcf without hedge settlements	$ 1.40	$ 1.81	$ (0.41)	(23%)
Oil price per Bbl with hedge settlements	$ 62.00	$ 60.24	$ 1.76	3%
Oil price per Bbl without hedge settlements	$ 61.31	$ 67.10	$ (5.79)	(9%)
NGL price per Bbl without hedge settlements	$ 13.00	$ 22.22	$ (9.22)	(41%)
Total price per Boe with hedge settlements	$ 49.12	$ 45.84	$ 3.28	7%
Total price per Boe without hedge settlements	$ 48.24	$ 50.21	$ (1.97)	(4%)
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 27.71	$ 16.36	$ 11.35	69%
Lease operating expenses	$ 25.58	$ 13.93	$ 11.65	84%
Production taxes	$ 2.14	$ 2.43	$ (0.29)	(12%)
Depreciation, depletion and amortization	$ 12.55	$ 10.60	$ 1.95	18%

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

Production. For the three months ended June 30, 2019, 74% of our production was oil, 14% was NGLs and 12% was natural gas as compared to the three months ended June 30, 2018, where 67% of our production was oil, 15% was NGLs and 18% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2018 that were rich in natural gas. Combined production decreased by 52 MBoe for the three months ended June 30, 2019, primarily due to temporary takeaway capacity restraints in certain of our Texas producing assets, as well as the closing of the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

Natural gas, NGLs and oil sales. Unhedged oil sales decreased $2.3 million, or 43%, to approximately $3.0 million for the three months ended June 30, 2019, compared to approximately $5.3 million for the same period in 2018. NGL sales decreased approximately $0.3 million, or 71%, to approximately $0.1 million for the three months ended June 30, 2019, compared to approximately $0.4 million for the same period in 2018. Unhedged natural gas sales decreased $0.2 million, or 72%, to approximately $0.1 million for the three months ended June 30, 2019, compared to approximately $0.3 million for the same period in 2018. Total decrease in oil, natural gas and NGL sales for the three months ended June 30, 2019 was primarily the result of the same factors described under “Production” above.

Including hedges and mark-to-market activities, our total production-related revenue increased approximately $2.0 million for the three months ended June 30, 2019, compared to the same period in 2018. This increase was primarily the result of an increase of approximately $4.1 million in oil and natural gas mark-to-market activities and approximately $0.6 million in settlements on oil derivatives, offset by a decrease of approximately $2.7 million in oil, natural gas and NGL 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, 2019 (dollars in thousands, except average sales prices and volumes):

	Q2 2019 Production Volume	Q2 2018 Production Volume	Production Volume Difference	Q2 2018 Average Sales Price	Revenue Decrease due to Production
Natural gas (MMcf)	45	124	(79)	$ 1.81	$ (143)
Oil (MBbl)	49	79	(30)	$ 67.10	$ (2,013)
NGLs (MBbl)	9	18	(9)	$ 22.22	$ (200)
Total oil equivalent (MBoe)	66	118	(52)	$ 50.21	$ (2,356)

	Q2 2019 Average Sales Price	Q2 2018 Average Sales Price	Average Sales Price Difference	Q2 2019 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 1.40	$ 1.81	$ (0.41)	45	$ (18)
Oil (MBbl)	$ 61.31	$ 67.10	$ (5.79)	49	$ (284)
NGLs (MBbl)	$ 13.00	$ 22.22	$ (9.22)	9	$ (83)
Total oil equivalent (MBoe)	$ 48.24	$ 50.21	$ (1.97)	66	$ (385)

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, 2019 by approximately $0.3 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, 2019, the non-cash mark-to-market gain was approximately $0.9 million, compared to a loss of approximately $3.2 million for the same period in 2018. The 2019 non-cash gain resulted from lower future expected oil prices on these derivative transactions. Cash settlements received for our commodity derivative contracts were approximately $0.1 million for the three months ended June 30, 2019, compared to cash settlements paid of approximately $0.5 million for the three months ended June 30, 2018.

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, remained consistent for the three months ended June 30, 2019. However, lease operating expenses increased period over period on a cost per Boe basis due to decreased production from temporary takeaway capacity restraints in certain of our Texas producing assets during the three months ended June 30, 2019.

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, natural gas and NGL 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, 2019 decreased approximately $0.4 million to approximately $0.8 million, compared to approximately $1.3 million for the same period in 2018. This decrease is primarily the result of temporary takeaway capacity restraints in certain of our Texas producing assets, as well as the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

Impairment expense. For the three months ended June 30, 2019, and 2018 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, 2019	Three Months Ended June 30, 2018	Variance	Variance %
Reconciliation of segment operating income to net income (loss)				
Total production operating income	$ 1,481	$ 1,367	$ 114	8%
Total midstream operating income	9,611	9,138	473	5%
Total segment operating income	11,092	10,505	587	6%
General and administrative expense	(4,171)	(6,919)	2,748	(40%)
Unit-based compensation expense	(175)	(1,347)	1,172	(87%)
Interest expense, net	(2,814)	(2,780)	(34)	1%
Other income (expense)	21	(1,254)	1,275	NM [(a)]
Income tax expense	(76)	—	(76)	NM [(a)]
Net income (loss)	$ 3,877	$ (1,795)	$ 5,672	NM [(a)]

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

General and administrative expenses. General and administrative expenses include indirect costs billed by Manager in connection with the Services Agreement, field office expenses, professional fees and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, decreased by approximately $3.9 million, or 47%, to approximately 4.3 million for the three months ended June 30, 2019 compared to approximately $8.3 million for the same period in 2018. The decrease was primarily the result of reduced professional and management fees as well as a decrease in the unit price which is used to calculate the unit-based compensation expense.

Interest expense, net. Interest expense remained consistent for the three months ended June 30, 2019 with no material change when compared to the same period in 2018.

Income tax expense. Income tax expense was approximately $76 thousand for the three months ended June 30, 2019, compared to no expense recorded for the same period in 2018. The increase resulted from income taxes on gross margin within the state of Texas, which was primarily driven by a decrease in total operating expenses over the comparable periods and the removal of the valuation allowance.

Six months ended June 30, 2019 compared to six months ended June 30, 2018

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, 2019	Six Months Ended June 30, 2018	Variance	Variance %
Revenues:				
Gathering and transportation sales	$ 3,385	$ 3,349	$ 36	1%
Gathering and transportation lease revenues	32,226	25,486	6,740	26%
Total gathering and transportation sales	35,611	28,835	6,776	23%
Operating costs:				
Lease operating expenses	773	582	191	33%
Transportation operating expenses	5,724	5,918	(194)	(3%)
Depreciation and amortization	10,680	10,559	121	1%
Accretion expense	159	146	13	9%
Total operating expenses	17,336	17,205	131	1%
Other income:				
Earnings from equity investments	2,233	7,383	(5,150)	(70%)
Operating income	$ 20,508	$ 19,013	$ 1,495	8%

Gathering and transportation sales. Gathering and transportation sales remained relatively consistent for the six months ended June 30, 2019 with no material change when compared to the same period in 2018. Gathering and transportation lease revenues increased approximately $6.7 million, or 26%, to approximately $32.2 million compared to approximately $25.5 million for the same period in 2018. This increase was primarily the result of an increase in the rate charged for natural gas transported on Western Catarina Midstream that was produced from outside the dedicated acreage under the Gathering Agreement.

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 pipeline integrity management expenses. Our transportation operating expenses decreased slightly by approximately $0.2 million, or 3%, to approximately $5.7 million for the six months ended June 30, 2019, compared to approximately $5.9 million for the same period in 2018.

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 remained consistent for the six months ended June 30, 2019 with no material change when compared to the same period in 2018.

Earnings from equity investments. Earnings from equity investments decreased approximately $5.2 million, or 70%, to approximately $2.2 million for the six months ended June 30, 2019, compared to approximately $7.4 million for the same period in 2018. This decrease was the result of higher ad valorem taxes due to the addition of Silver Oak II to the Carnero JV as well as lower throughput during the six months ended June 30, 2019.

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 average unit costs):

	Six Months Ended			
	June 30,			
	2019	2018	Variance	
Revenues:				
Natural gas sales at market price	$ 213	$ 695	$ (482)	(69%)
Natural gas hedge settlements	(13)	26	(39)	NM [(a)]
Natural gas mark-to-market activities	166	(22)	188	NM [(a)]
Natural gas total	366	699	(333)	(48%)
Oil sales	6,749	10,703	(3,954)	(37%)
Oil hedge settlements	381	(772)	1,153	NM [(a)]
Oil mark-to-market activities	(4,058)	(4,885)	827	(17%)
Oil total	3,072	5,046	(1,974)	(39%)
NGL sales	296	995	(699)	(70%)
Total revenues	3,734	6,740	(3,006)	(45%)
Operating costs:				
Lease operating expenses	3,007	3,396	(389)	(11%)
Production taxes	324	609	(285)	(47%)
Gain on sale of assets	—	(2,388)	2,388	NM [(a)]
Depreciation, depletion and amortization	1,923	2,614	(691)	(26%)
Accretion expense	100	103	(3)	(3%)
Total operating expenses	5,354	4,334	1,020	24%
Operating income (loss)	$ (1,620)	$ 2,406	$ (4,026)	NM [(a)]

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

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Variance	
Net production:				
Natural gas (MMcf)	99	306	(207)	(68%)
Oil production (MBbl)	113	164	(51)	(31%)
NGLs (MBbl)	21	44	(23)	(52%)
Total production (MBoe)	151	259	(108)	(42%)
Average daily production (Boe/d)	834	1,431	(597)	(42%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 2.02	$ 2.36	$ (0.34)	(14%)
Natural gas price per Mcf without hedge settlements	$ 2.15	$ 2.27	$ (0.12)	(5%)
Oil price per Bbl with hedge settlements	$ 63.10	$ 60.55	$ 2.55	4%
Oil price per Bbl without hedge settlements	$ 59.73	$ 65.26	$ (5.53)	(8%)
NGL price per Bbl without hedge settlements	$ 14.10	$ 22.61	$ (8.51)	(38%)
Total price per Boe with hedge settlements	$ 50.50	$ 44.97	$ 5.53	12%
Total price per Boe without hedge settlements	$ 48.07	$ 47.85	$ 0.22	0%
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 22.06	$ 15.46	$ 6.60	43%
Lease operating expenses	$ 19.91	$ 13.11	$ 6.80	52%
Production taxes	$ 2.15	$ 2.35	$ (0.20)	(9%)
Depreciation, depletion and amortization	$ 12.74	$ 10.09	$ 2.65	26%

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

Production. For the six months ended June 30, 2019, 75% of our production was oil, 14% was NGLs and 11% was natural gas as compared to the six months ended June 30, 2018, where 63% of our production was oil, 17% was NGLs and 20% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2018 that were rich in natural gas. Combined production decreased by 108 MBoe for the six months ended June 30, 2019, primarily due to temporary takeaway capacity restraints in certain of our Texas producing assets, as well as the closing of the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

Natural gas, NGLs and oil sales. Unhedged oil sales decreased $4.0 million, or 37%, to approximately $6.7 million for the six months ended June 30, 2019, compared to approximately $10.7 million for the same period in 2018. NGL sales decreased approximately $0.7 million, or 70%, to approximately $0.3 million for the six months ended June 30, 2019, compared to approximately $1.0 million for the same period in 2018. Unhedged natural gas sales decreased $0.5 million, or 69%, to approximately $0.2 million for the six months ended June 30, 2019, compared to approximately $0.7 million for the same period in 2018. Total decrease in oil, natural gas and NGL sales for the six months ended June 30, 2019 was primarily the result of the same factors described under "Production" above.

Including hedges and mark-to-market activities, our total production-related revenue decreased approximately $3.0 million for the six months ended June 30, 2019, compared to the same period in 2018. This decrease was primarily the result of a decrease of approximately $5.1 million in oil, natural gas and NGL sales, offset by an increase of approximately $1.1 million in settlements on oil and natural gas derivate contracts and approximately $1.0 million in oil and natural gas mark-to-market activities.

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, 2019 (dollars in thousands, except average sales prices and volumes):

	2019 Production Volume	2018 Production Volume	Production Volume Difference	2018 Average Sales Price	Revenue Decrease due to Production
Natural gas (MMcf)	99	306	(207)	$ 2.27	$ (470)
Oil (MBbl)	113	164	(51)	$ 65.26	$ (3,328)
NGLs (MBbl)	21	44	(23)	$ 22.61	$ (520)
Total oil equivalent (MBoe)	151	259	(108)	$ 47.85	$ (4,318)

	2019 Average Sales Price	2018 Average Sales Price	Average Sales Price Difference	2019 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 2.15	$ 2.27	$ (0.12)	99	$ (12)
Oil (MBbl)	$ 59.73	$ 65.26	$ (5.53)	113	$ (625)
NGLs (MBbl)	$ 14.10	$ 22.61	$ (8.51)	21	$ (179)
Total oil equivalent (MBoe)	$ 48.07	$ 47.85	$ 0.22	151	$ (816)

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, 2019 by approximately $0.7 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, 2019, the non-cash mark-to-market loss was approximately $3.9 million, compared to a loss of approximately $4.9 million for the same period in 2018. The 2019 non-cash loss resulted from higher future expected oil prices on these derivative transactions. Cash settlements received for our commodity derivative contracts were approximately $0.4 million for the six months ended June 30, 2019, compared to cash settlements paid of approximately $0.7 million for the six months ended June 30, 2018.

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 approximately $0.4 million, or 11%, to approximately $3.0 million for the six months ended June 30, 2019, compared to approximately $3.4 million for the same period in 2018. This decrease in operating expenses was primarily due to the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture. Lease operating expenses per BOE, however, increased period over period due to decreased production from temporary takeaway capacity restraints in certain of our Texas producing assets during the six months ended June 30, 2019.

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, natural gas and NGL 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, 2019 decreased approximately $0.7 million to approximately $1.9 million, compared to approximately $2.6 million for the same period in 2018. This decrease is primarily the result of temporary takeaway capacity restraints in certain of our Texas producing assets, as well as the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

Impairment expense. For the six months ended June 30, 2019, and 2018 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):

	Six Months Ended June 30,			
	2019	2018	Variance	
Reconciliation of segment operating income (loss) to net income (loss)				
Total production operating income (loss)	$ (1,620)	$ 2,406	$ (4,026)	NM [(a)]
Total midstream operating income	20,508	19,013	1,495	8%
Total segment operating income	18,888	21,419	(2,531)	(12%)
General and administrative expense	(8,920)	(12,084)	3,164	(26%)
Unit-based compensation expense	(810)	(2,785)	1,975	(71%)
Interest expense, net	(5,600)	(5,379)	(221)	4%
Other income (expense)	67	(1,524)	1,591	NM [(a)]
Income tax expense	(122)	—	(122)	NM [(a)]
Net income (loss)	$ 3,503	$ (353)	$ 3,856	NM [(a)]

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

General and administrative expenses. General and administrative expenses include indirect costs billed by Manager in connection with the Services Agreement, field office expenses, professional fees and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, decreased by approximately $5.1 million, or 35%, to approximately $9.7 million for the six months ended June 30, 2019 compared to approximately $14.9 million for the same period in 2018. The decrease was primarily the result of reduced professional and management fees as well as a decrease in the unit price which is used to calculate the unit-based compensation expense.

Interest expense, net. Interest expense increased $0.2 million, or 4%, to approximately $5.6 million for the six months ended June 30, 2019, compared to approximately $5.4 million for the same period in 2018. This increase was the result of higher interest rates for the six months ended June 30, 2019.

Income tax expense. Income tax expense was approximately $122 thousand for the six months ended June 30, 2019, compared to no expense recorded for the same period in 2018. The increase resulted from income taxes on gross margin within the state of Texas, which was primarily driven by a decrease in total operating expenses over the comparable periods and the removal of the valuation allowance.

Liquidity and Capital Resources

As of June 30, 2019, we had approximately $1.3 million in cash and cash equivalents and $38.0 million available for borrowing under the Credit Agreement in effect on such date.

During the three months ended June 30, 2019, we paid approximately $2.5 million in cash for interest on borrowings under our Credit Agreement, of which approximately $42.7 thousand was related to the fee on undrawn commitments. During the six months ended June 30, 2019, we paid approximately $5.1 million in cash for interest on borrowings under our Credit Agreement, of which approximately $80.3 thousand was related to the fee on undrawn commitments.

Our capital expenditures during the three and six months ended June 30, 2019 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 any quarterly cash distributions.

We expect that our future cash requirements relating to working capital, maintenance capital expenditures and any 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 (the “Credit Agreement”) 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.

Our Credit Agreement is a current liability that matures on March 31, 2020. We expect to refinance or extend the maturity of our credit agreement prior to its maturity date. However, we may not be able to refinance or extend the maturity of our credit agreement or, if we are able to refinance or extend the maturity, we may not be able to do so with borrowing and debt issue costs, terms, covenants, restrictions, commitment amount or a borrowing base favorable to us.

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 the 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, 2019, the borrowing base under the Credit Agreement was $303.1 million, with an elected commitment amount of $210.0 million. On July 9, 2019, we received a notification that, pursuant to the terms of the Credit Agreement, our lenders had undertaken a borrowing base review, which resulted in a borrowing base redetermination of $282.0 million. Following such review, the elected commitment amount remained unchanged at $210.0 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 ratio for at least 1.0 to 1.0 at all times;
- Senior secured net debt to consolidated Adjusted EBITDA ratio 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 for the proper conduct of our business and the payment of fees and expenses.

At June 30, 2019, 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 under the Credit Agreement 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, 2019, the elected commitment amount under our Credit Agreement was set at $210.0 million, and we had $172.0 million of debt outstanding under the facility, leaving us with $38.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of June 30, 2019. 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.

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.

The following tables as of June 30, 2019, 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
2019	—	$ —	—	$ —	57,024	$ 60.48	54,824	$ 60.52	111,848	$ 60.50
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50
									312,432	

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
2019	—	$ —	—	$ —	112,032	$ 2.85	108,552	$ 2.85	220,584	$ 2.85
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85
									623,032	

Operating Cash Flows

We had net cash flows provided by operating activities for the six months ended June 30, 2019 of approximately $30.1 million, compared to net cash flows provided by operating activities of approximately $37.1 million for the same period in 2018. This decrease was primarily related to the impact of lower commodity prices and production between the periods resulting in a decrease of approximately $5.1 million, as well as a decrease on net cash settlements received on commodity derivative contracts of approximately $1.2 million between the periods.

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 used in investing activities for the six months ended June 30, 2019 of approximately $0.7 million, substantially all of which were related to midstream activities.

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

Financing Activities

Net cash flows used in financing activities was approximately $31.1 million for the six months ended June 30, 2019. During the six months ended June 30, 2019, we distributed approximately $17.7 million and $5.2 million to Class B Preferred Unitholders and common unitholders, respectively. Additionally, we repaid borrowings of $8.0 million under our Credit Agreement.

Net cash flows used in financing activities were approximately $36.2 million for the six months ended June 30, 2018. During the six months ended June 30, 2018, we distributed approximately $17.5 million and $13.6 million to Class B Preferred Unitholders and common unitholders, respectively. Additionally, we paid approximately $0.1 million in offering costs and repaid $5.0 million of borrowings under our Credit Agreement.

Off-Balance Sheet Arrangements

As of June 30, 2019, 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 generation of substantially all of our midstream business segment revenues from a single customer, Sanchez Energy, the sale of oil and natural gas and our use of derivatives. On July 15, 2019, Sanchez Energy filed a current report on Form 8-K stating that it is currently in advanced discussions with certain of its bondholders and other stakeholders regarding a comprehensive restructuring plan to reduce Sanchez Energy's debt and strengthen its overall financial flexibility. No assurances can be given as to the timing or outcome of this process. Through June 30, 2019, we have not suffered any significant losses with our counterparties as a result of non-performance. Any development that materially and adversely affect Sanchez Energy's operations or financial condition could have a material adverse impact on us. For additional information on the risks associated with our relationships with Sanchez Energy, please read "Part I, Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2018.

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, 2019, 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, 2018, which was filed with the SEC on March 7, 2019. 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 a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

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, 2019 (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, 2019 that have materially affected, or are reasonably likely to materially affect, 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

Carefully consider the risk factors under the caption “Risk Factors” under Part I, Item 1A in our Annual Report on Form 10-K for the year ended December 31, 2018, together with all of the other information included in this Form 10-Q 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

In connection with providing services under the Services Agreement for the first-quarter 2019, the Partnership issued 887,269 common units to Manager on May 3, 2019. See Note 13 “Related Party Transactions” and the information incorporated by reference therein for additional information related to the Services Agreement. The issuance of these common units was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof as a transaction by an issuer not involving a public offering.

No common units were purchased in the second-quarter of 2019.

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.

EXHIBIT INDEX

Exhibit Number	Description
10.1*+	Form of Executive Services Agreement.
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.

\+ Management contract or compensatory plan or arrangement.

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 8, 2019 By /s/ Charles C. Ward

Charles C. Ward
Chief Financial Officer and Secretary
(Duly Authorized Officer and Principal Financial Officer)

Exhibit 10.1

Execution Version

FORM OF EXECUTIVE SERVICES AGREEMENT

THIS EXECUTIVE SERVICES AGREEMENT (this "Agreement") is made and entered into as of August 2, 2019 (the "Effective Date"), by and between [•] ("Executive") and Sanchez Midstream Partners GP LLC, a Delaware limited liability company ("Company") and the general partner of Sanchez Midstream Partners LP, a Delaware limited partnership ("Partnership," and together with Company, the "Partnership Parties"). Executive and Company are collectively referred to herein as the "Parties," and individually as a "Party."

WHEREAS, Executive is the [•] and provides services for and on behalf of the Partnership Parties; and

WHEREAS, the Parties wish to memorialize their agreement with respect to the terms and conditions of Executive's continued employment as the [•] of the Company.

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties, intending to be legally bound, mutually agree as follows:

1. **Term**: Executive agrees to continue to provide services for the Partnership Parties and the Company agrees to continue to engage Executive to serve as the Company's [•], pursuant to the terms and conditions of this Agreement and continuing until Executive's services are terminated by either Executive or the Company, as applicable, in accordance with Section 4 below (the "Term").

2. **Place of Services**: Executive will perform his duties under this Agreement at the Partnership Parties' offices in Houston, Texas.

3. **Compensation**: During the Term of this Agreement, the Company agrees as follows:

(a) Base Salary: Executive's annual base salary is $[•], subject to applicable withholdings and deductions (the "Base Salary"). Executive's Base Salary may not be decreased during the Term of this Agreement by the Company, but may be increased in the absolute discretion of the Company's Board of Directors (the "Board"), or, if applicable, an authorized committee thereof, in accordance with the rules and procedures governing the Board. To the extent Executive's Base Salary is increased during the Term, such increased rate shall thereafter be considered Executive's "Base Salary" for purposes of this Agreement.

(b) Annual Bonus: In addition to Executive's Base Salary, during the Term Executive shall continue to receive an annual cash bonus for services rendered by Executive to the Partnership Parties equal to an amount between [•] ([•]%) and [•] ([•]%) of Executive's Base Salary, as determined by the Board, in its sole discretion, subject to applicable withholdings and deductions (the "Annual Bonus"). Fifty percent (50%) of the Annual Bonus shall be payable to Executive no later than September 30 of the year for which such Annual Bonus relates, and the remainder of the Annual Bonus, including any true-up and changes determined by the Board, in its sole discretion, shall be payable to Executive no later than March 31 of the year following the year for which such Annual Bonus relates. For the avoidance of doubt, fifty percent (50%) of Executive's Annual Bonus for fiscal 2019 shall be paid no later than September 30, 2019 and the remainder of such Annual Bonus shall be paid no later than March 31, 2020 and shall include any amounts approved as part of the Annual Bonus by the Board. Executive's Annual Bonus shall be determined in a manner and utilizing a qualitative assessment of financial and individual performance achievements consistent with the determination of Executive's Annual Bonus in prior years; provided, that, the Annual Bonus may not be decreased by the Company during the term of this Agreement, but may be increased in the absolute discretion of the Board, or, if applicable, an authorized committee thereof, in accordance with the rules and procedures governing the Board. To the extent Executive's Annual Bonus is increased during the Term, such increased rate shall thereafter be considered Executive's "Annual Bonus" for purposes of this Agreement.

(c) Long-Term Incentive Compensation Awards: Executive shall be eligible to receive awards under the Sanchez Midstream Partners LP Long-Term Incentive Plan or any successor thereto (the "Plan") and to participate in any long-term incentive programs available generally to the Company's executive officers in the future, both as determined in the sole discretion of the Board, or, if applicable, a committee thereof.

(d) Additional Bonus. If, as of the date that an award under the Plan (or other applicable long-term incentive program of the Company) as described in Section 3(c) above would otherwise be granted, (i) either (1) the common units representing limited partner interests in the Partnership ("Common Units") are no longer publicly traded on (A) any exchange registered with the Securities and Exchange Commission (the "SEC") under Section 6(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") (or any successor to such Section), or (B) any other securities exchange (whether or not registered with the SEC under Section 6(a) (or any successor to such Section) of the Exchange Act) that the Company shall designate as a "National Securities Exchange" for purposes of the Partnership Agreement or the Partnership has otherwise been delisted, (2) the Board has made a public announcement that the Partnership will no longer make cash distributions on the Common Units, or (3) the Board has made a formal determination in writing that no cash distributions will be made on the Common Units for the first quarter of the applicable calendar year, and (ii) as a result of the event(s) described in clause (i), the Board (or the applicable committee) in its discretion elects not to grant any award to the Executive under the Plan (or other applicable long-term incentive program) pursuant to paragraph (c) above, then the Executive will be entitled to an additional cash bonus award, in an amount to be determined by the Board in its discretion and which shall be paid to the Executive at the same time the Annual Bonus is paid (each such additional cash bonus award, an "Additional Bonus"). Notwithstanding the foregoing, no bonus shall be paid in substitution for compensation subject to (and not exempt from) Section 409A of the Code, to the extent such payment would result in the imposition of additional tax, interest and/or penalties upon Executive under Section 409A of the Code.

4. Termination

(a) Services Terminable At-Will; Notice of Termination: The Term and Executive's appointment as an officer of the Company may be terminated by Executive or the Company at any time and for any reason; provided, that, any purported termination by Executive or the Company shall be communicated by a written "Notice of Termination" to the other in accordance with Section 18 below. The Notice of Termination shall (i) indicate the specific termination provision of this Agreement relied upon, (ii) to the extent applicable, set forth in reasonable detail the facts and circumstances claimed to provide a basis for the termination of Executive's services, under the provision so indicated, and (iii) specify the effective "Termination Date" of Executive's services to the Partnership Parties (which shall not be earlier than the date the Notice of Termination is sent, and shall not be later than thirty (30) days after the date of the Notice of Termination is sent).

(b) Definitions: For purposes of this Agreement, the following definitions shall apply:

(i) Affiliate: means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

(ii) Cause: the Company will have "Cause" to terminate Executive's services under this Agreement for any of the following reasons:

(A) Executive's conviction of, or plea of nolo contendere to, any felony or crime involving moral turpitude in connection with the performance of his duties to the Partnership Parties;

(B) Executive being charged with, or a defendant in, an action brought by the SEC or another federal or state regulator based primarily on Executive's individual alleged acts or omissions during Executive's appointment as an officer of, or while providing services to, the Partnership Parties;

(C) Executive's commission of a willful and material act of fraud or embezzlement of the Company's funds or other assets causing material damage to the Company; or

(D) Executive's willful and material misrepresentations or concealments on any written reports submitted to the Board;

provided, that, any of the events described in Section 4(b)(ii)(C) or Section 4(b)(ii)(D) above shall constitute Cause only if Executive fails to cure such event to the reasonable satisfaction of the Board within thirty (30) calendar days of receiving written notice from the Board of the event which allegedly constitutes Cause; and provided further that a termination shall not be deemed to be for Cause under Section 4(b)(ii)(C) or Section 4(b)(ii)(D) unless and until there shall have been delivered to Executive a copy of a resolution duly adopted by the affirmative vote of a majority of the members of the Board (other than Executive), at a meeting of the Board called and held for such purpose (after reasonable notice is provided to Executive, and Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, Executive is guilty of the conduct described in Section 4(b)(ii)(C) or Section 4(b)(ii)(D), above, and specifying the particulars thereof in detail.

For the purposes of this provision, no act or failure to act on the part of Executive shall be considered "willful" unless it is done, or omitted to be done, by Executive in bad faith and without reasonable belief that Executive's actions or omission was in the best interests of the Partnership Parties. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board, or upon the instructions of the Board, or based upon the advice of counsel for the Company, shall be conclusively presumed to be done, or omitted to be done, by Executive in good faith and in the best interests of the Partnership Parties.

(iii) Change in Control: means the occurrence of any of the following events: (A) the Company withdraws or is removed as the general partner of the Partnership, (B) the Company transfers any portion of its general partner interest in the Partnership to any Person other than an Affiliate of the Company, (C) any merger, consolidation or other transaction involving the Partnership or the Company and another Person (other than an Affiliate thereof), whether in one or a series of related transactions, which results in one or more Persons directly or indirectly acquiring control over more than fifty percent (50%) of the equity interests of the Partnership or the Company, as applicable, (D) the direct or indirect sale, transfer, conveyance or other disposition, in one or a series of related transactions, of all or substantially all of the assets of the Partnership, (E) any dissolution or liquidation of the Partnership or the Company (other than in connection with a bankruptcy proceeding or a statutory winding up); or (F) any other transaction pursuant to which the Company or any Affiliate controlled by the Company exercises its rights to purchase all of the Partnership's common units representing limited partner interests ("Common Units") pursuant to Section 15.1 of the Agreement of Limited Partnership of the Partnership, as amended (the "Partnership Agreement").

(iv) Common Unit Price: means (A) if the consideration to be received in the Change in Control by the holders of Common Units is solely cash, the amount of cash consideration per Common Unit or (B) if the consideration to be received in the Change in Control by holders of Common Units is other than solely cash (1) the average of the closing sale prices per Common Unit (or, if no closing sale price is reported, the average of the closing bid and ask prices or, if more than one in either case, the average of the average closing bid and the average closing ask prices) for the ten (10) consecutive trading days immediately preceding, but not including, the effective date of the Change in Control as reported on the principal U.S. securities exchange on which the Common Units are then traded, or (2) the average of the last quoted bid prices for the Common Units in the over-the-counter market as reported by OTC Market Group Inc. or similar organization for the ten (10) consecutive trading days immediately preceding, but not including, the effective date of the Change in Control, if the Common Units are not then listed for trading on a U.S. securities exchange.

(v) Good Reason: Executive will have "Good Reason" to terminate his appointment as an officer of the Company under this Agreement for any of the following reasons to which Executive does not consent in writing:

(A) the relocation of Executive's primary place of performing services for the Partnership Parties to a location more than fifty (50) miles from Executive's primary place of performing services as set forth in Section 2;

(B) a material diminution in Executive's Base Salary;

(C) a material diminution in the authority, duties or responsibilities of Executive to the Partnership Parties; or

(D) any other action or inaction that constitutes the Company's material breach of any provision of this Agreement;

provided, that, any of the conditions described in Section 4(b)(v)(A) through 4(b)(v)(D) above shall constitute Good Reason only if the Company fails to cure such condition to the reasonable satisfaction of Executive within thirty (30) calendar days of receiving written notice from Executive of the condition which allegedly constitutes Good Reason; and provided further, that, Executive's termination shall constitute a termination by Executive for Good Reason only if the Termination Date occurs not later than ninety (90) calendar days following the initial existence of one or more of the conditions described in Section 4(b)(v)(A) through 4(b)(v)(D) above.

(vi) Disability: For purposes of this Agreement, "Disability" shall mean the earlier of:

(A) a written determination by a physician that Executive has been unable to substantially perform his usual and customary services for the Partnership Parties under this Agreement for a period of at least one hundred twenty (120) consecutive days (or one hundred eighty (180) non-consecutive days) during any twelve (12) month period as a result of Executive's incapacity due to mental or physical illness; or

(B) "disability" as such term is defined in the Company's applicable long-term disability insurance plan as it is in effect at the time Executive becomes Disabled.

(vii) Person: means any individual, corporation, limited liability company, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof, or other entity.

(c) Compensation Upon Certain Events.

(i) Termination by the Company for Cause or by Executive Without Good Reason: If Executive's appointment as an officer of the Company hereunder is terminated by the Company for Cause or by Executive without Good Reason, then::

(A) Company shall pay to Executive an amount equal to Executive's accrued but unpaid then-current Base Salary through the Termination Date, and

(B) the treatment of each long-term incentive compensation award shall be governed by the terms and conditions of the applicable award agreement for such award and the Plan or similar incentive award program under which such award was granted.

(ii) Termination Upon Executive's Death or Disability: Upon Executive's death or Disability:

(A) Company shall pay to Executive (or his designated beneficiaries), an amount equal to Executive's accrued but unpaid then-current Base Salary through the Termination Date;

(B) to the extent not yet paid to Executive (or his designated beneficiaries), Company shall pay to Executive (or his designated beneficiaries) (1) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (2) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(C) any units which may have been awarded to Executive under the Plan or any other long-term incentive programs available generally to the Company's executive officers in the future, in each case, shall vest in full as of the Termination Date and convert into Common Units as set forth in the applicable award agreement.

(iii) Termination by the Company Without Cause or by Executive for Good Reason: If Executive's appointment as an officer of the Company hereunder is terminated by the Company without Cause, or by Executive for Good Reason, then:

(A) Company shall pay to Executive an amount equal to (1) two hundred percent (200%) of Executive's Base Salary; *plus* (2) two hundred percent (200%) of the largest Annual Bonus (including the amount of any Additional Bonus, if applicable) paid to (or due to be paid to) Executive for the year in which the Termination Date occurred or any year in the three (3)-calendar year period immediately preceding the Termination Date, which shall be paid in a single lump sum within fourteen (14) calendar days of the Termination Date;

(B) if Executive timely elects continuation coverage under COBRA, then the Company shall pay the COBRA premiums for Executive and his eligible dependents directly to the applicable insurer(s) during the COBRA continuation period;

(C) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date, an amount equal to all outstanding amounts owed to Executive for services performed by Executive for or on behalf of the Partnership Parties, including, without limitation, (1) the amount of Executive's accrued but unpaid then current Base Salary through the Termination Date, and (2) to the extent not yet paid to Executive, (a) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (b) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(D) any units which may have been awarded to Executive under the Plan or any other long-term incentive programs available generally to the Company's executive officers in the future, in each case, shall vest in full as of the Termination Date and convert into Common Units as set forth in the applicable award agreement.

(iv) Change in Control: If, during the period beginning sixty (60) days prior to and ending two (2) years immediately following a Change in Control, either (A) Company terminates the Executive's employment without Cause, (B) the Executive's death occurs, (C) the Executive becomes Disabled, or (D) the Executive terminates his employment with Company for any reason, in each case constituting a "separation from service" within the meaning of Section 409A of the Internal Revenue Code of 1986 (the "Code") ("Separation from Service"), then:

(A) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date: an amount equal to (1) two hundred percent (200%) of Executive's then-current Base Salary; *plus* (2) two hundred percent (200%) of the largest Annual Bonus (including the amount of any Additional Bonus, if applicable) paid to (or due to be paid to) Executive for the year in which the Termination Date occurred or any year in the three calendar year period immediately preceding the Termination Date;

(B) if Executive timely elects continuation coverage under COBRA, then Company shall pay the COBRA premiums for Executive and his eligible dependents directly to the applicable insurer(s) during the COBRA continuation period;

(C) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date, an amount equal to all outstanding amounts owed to Executive for services performed by Executive for or on behalf of the Partnership Parties, including, without limitation, (1) the amount of Executive's accrued but unpaid then current Base Salary through the Termination Date, and (2) to the extent not yet paid to Executive, (a) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (b) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(D) any units which may have been awarded to Executive under the Plan shall vest in full as of the date of the Change in Control and convert into Common Units as set forth in the applicable award agreement.

(d) Attorneys' Fees: In the event that Executive substantially prevails in a litigation regarding whether (i) Executive's services were terminated for Cause, or (ii) Executive resigned for Good Reason, Executive shall be entitled to an award including the attorneys' fees and costs Executive incurs in connection with such litigation (including any appeals thereof).

(e) No Mitigation or Offset: Executive shall not be required to mitigate the amount of any payment or other obligation of Company provided for in this Agreement by seeking retention as an independent contractor, employment, or otherwise, and no such payment or other obligation of Company shall be offset or reduced by the amount of any compensation provided to Executive in any subsequent independent contractor or employment relationship.

5. Indemnification: Company agrees to hold harmless and indemnify Executive for any acts or omissions taken or made by Executive during the Term within the scope of his authority as the [•] of the Company to the greatest extent allowed by applicable law. Without limiting the foregoing, Executive's right to indemnity hereunder shall include the Company's advancement of all costs and expenses (including attorneys' fees and expenses) in connection with the defense of any actual or threatened claim, subject to Company's receipt of an undertaking by Executive to repay such amount if it shall ultimately be determined that Executive is not entitled to be indemnified by Company as authorized by this Agreement. Additionally, during the Term, and for at least six (6) years following the termination of Executive's appointment as an officer of the Company (regardless of the reason for such termination), Company shall maintain directors and officers insurance for the benefit of Executive that is no less favorable than the directors and officers insurance provided to any other director, officer, or executive of the Company. The rights provided in this Section 5 are in addition to any other rights to indemnification, exculpation, or contribution Executive may otherwise have under any agreement, contract, policy, by-law, certificate of incorporation, or otherwise.

6. Section 409A of the Code:

(a) This Agreement is intended to comply with, or be exempt from, Section 409A of the Code and will be interpreted accordingly. Notwithstanding anything in this Agreement to the contrary, any references under this Agreement to the termination of Executive's appointment as an officer of the Company, or "Termination Date" shall be deemed to refer to the date upon which Executive has experienced a Separation from Service. It is the intent of the Parties that all compensation and benefits payable or provided to Executive (whether under this Agreement or otherwise) shall fully comply with the requirements of Section 409A of the Code. Accordingly, Company agrees that it will not, without Executive's prior written consent, take any action inconsistent with this Agreement that would result in the imposition of tax, interest and/or penalties upon Executive under Section 409A of the Code.

(b) Notwithstanding any provision in this Agreement or elsewhere to the contrary, if upon a termination of employment Executive is deemed to be a "specified employee" within the meaning of Section 409A using the identification methodology selected by Company from time to time, or if none, the default methodology under Section 409A, any payments or benefits due upon a termination of Executive's employment under any arrangement that constitutes a "deferral of compensation" within the meaning of Section 409A shall be delayed and paid or provided (or commence, in the case of installments) on the first payroll date on or following the earlier of (i) the date which is six (6) months and one (1) day after Executive's termination of employment for any reason other than death (the "Delayed Payment Date"), and (ii) the date of Executive's death, and any remaining payments and benefits shall be paid or provided in accordance with the normal payment dates specified for such payment or benefit; provided, that, payments or benefits that qualify as short-term deferral (within the meaning of Section 409A and Final Treasury Regulations Section 1.409A-1(b)(4)) or involuntary separation pay (within the meaning of Section 409A and Final Treasury Regulations Section 1.409A-1(b)(9)(iii)(A)) and are otherwise permissible under Section 409A and the Final Treasury Regulations, shall not be subject to such six-month delay. On the Delayed Payment Date, Company will pay to Executive a lump sum equal to all amounts that would have been paid during the period of the delay if the delay were not required plus interest on such amount at a rate equal to the short-term applicable federal rate then in effect, and will thereafter continue to pay Executive the Severance Payment in installments in accordance with this Section. Additionally, to the extent that Executive's receipt of any in-kind benefits from Company or its Affiliates must be delayed pursuant to this Section 6(b), Executive may elect to instead purchase and receive such benefits during the period in which the provision of benefits would otherwise be delayed by paying Company or its Affiliates, as applicable, for the fair market value of such benefits (as determined by Company in good faith) during such period. Any amounts paid by the Company pursuant to the preceding sentence shall be reimbursed to Executive (with interest thereon) as described above on the date that is six (6) months following

Executive's Separation From Service.

(c) Each payment made under this Agreement shall be designated as a "separate payment" within the meaning of Section 409A of the Code.

(d) To the extent that any payment hereunder is subject to Section 409A of the Code and may be payable in one of two calendar years, payment shall be made in the later year.

(e) In the event that either Executive or Company's senior management becomes aware that any provision of this Agreement violates Section 409A of the Code, the Parties will meet and confer regarding such issues and will engage in good faith discussions regarding whether and how the Agreement can be modified so as to minimize the likelihood of a Section 409A violation while providing Executive with financial terms substantially commensurate to those set forth in this Agreement.

(f) Notwithstanding the foregoing, the Company and the Partnership make no representations or warranties and will have no liability to Executive or any other person if any provisions of or payments under this Agreement are determined to constitute deferred compensation subject to Section 409A of the Code but not to satisfy the conditions of Section 409A of the Code.

7. Tax Withholding. Company may withhold from any payments or benefits referenced under this Agreement, and payable from the Company to Executive, all federal, state, city or other taxes as shall be required pursuant to any law or governmental regulation or ruling, and any deductions authorized by Executive.

8. Entire Agreement: This Agreement constitutes the entire agreement between Executive and Company with respect to the subject matter hereof and supersedes any and all prior agreements, understandings, discussions, negotiations, and/or undertakings, whether written or oral. Executive specifically agrees that Executive is not relying on any representations, promises, understandings, discussions, negotiations, or undertakings, whether written or oral, express or implied, other than those contained in this Agreement. Notwithstanding the foregoing, for the avoidance of doubt, nothing in this Agreement supersedes or affects the validity of any indemnification agreement, long term incentive plan, or equity, severance, bonus or other similar agreement between Executive and Company, or any of its parents, subsidiaries, affiliates, or related companies, or any of their successors, which shall remain in effect in accordance with their terms.

9. Governing Law: This Agreement shall be interpreted and enforced in accordance with the laws of the State of Texas, without regard to the principles of conflict of laws.

10. Invalid or Unenforceable Provisions: If any provision of this Agreement is determined to be unenforceable as a matter of governing law, a reviewing shall have the authority to "blue pencil" or otherwise modify such provision so as to render it enforceable while maintaining the Parties' original intent (as reflected herein) to the maximum extent possible. This Agreement shall be severable, and the invalidity or unenforceability of any particular provision of this Agreement shall not affect the other provisions hereof.

11. **Successors and Assigns; Third Party Beneficiary**:

(a) This Agreement shall be binding upon and shall inure to the benefit of Company, and its successors and assigns, and Company shall require any successor or assign to expressly assume and agree to perform this Agreement in the same manner and to the same extent that Company would be required to perform this Agreement if no such succession or assignment had taken place. The term "Company" as used herein shall include each such entity's successors and assigns. The term "successors and assigns" as used herein shall include, without limitation, a corporation or other entity acquiring a majority ownership of Company or all or substantially all the assets and business of Company (including this Agreement), whether by operation of law or otherwise.

(b) Neither this Agreement nor any right or interest hereunder shall be assignable or transferable by Executive, or by Executive's beneficiaries or legal representatives, except by will or by the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by Executive's legal personal representative.

12. **No Waiver**: No failure on the part of any Party at any time to require the performance by any other Party of any term of this Agreement shall be taken or held to be a waiver of such term or in any way affect such Party's right to enforce such term, and no waiver on the part of any Party of any term of this Agreement shall be taken or held to be a waiver of any other term hereof or the breach hereof.

13. **Modification or Amendment**: This Agreement may not be modified, altered, or amended, nor shall any new contract be entered into between the Parties hereto, except in a writing signed by both Executive and the Board.

14. **Headings**: Headings and other captions in this Agreement are for convenience of reference only and shall not be used in interpreting, construing, or enforcing any of the provisions of this Agreement.

15. **Construction**: The Parties have had ample opportunity to review, and have in fact reviewed and understand, this Agreement. Accordingly, the normal rule of construction, to the effect that any ambiguities are to be resolved against the drafting party, shall not be employed in the interpretation of this Agreement. For purposes of this Agreement, the connectives "and," "or," and "and/or" shall be construed either disjunctively or conjunctively as necessary to bring within the scope of a sentence or clause all subject matter that might otherwise be construed to be outside of its scope.

16. **Counterparts**. This Agreement may be executed in counterparts, each of which shall be deemed an original and both of which together shall constitute one and the same instrument. Facsimile, PDF, and other true and accurate copies of this Agreement shall have the same force and effect as originals hereof.

17. **Right to Counsel**: Each Party, including Executive, acknowledges that such Party has had the right to seek the advice of independent legal counsel prior to the execution of this Agreement. By executing this Agreement, each Party warrants and represents to each other Party that (i) the executing Party has consulted with an attorney of the executing Party's choice prior to the execution of this Agreement, to the extent such Party chose to do so, and (ii) that the executing Party understands each and every term and provision of this Agreement without explanation by any other Party. Each Party warrants and represents that such Party is under no duress or other coercion to sign this Agreement and that such Party is signing this Agreement of such Party's own free will.

18. **Notices**: All notices and all other communications provided for in this Agreement (including the Notice of Termination) shall be provided in writing and shall be sent via overnight delivery (with proof of delivery retained by the sending Party) to the following addresses:

IF TO COMPANY:

Sanchez Midstream Partners GP LLC
c/o s Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002
Attention: General Counsel

With a copy to:

Hunton Andrews Kurth LLP
600 Travis Street, Suite 4200
Houston, Texas 77002
Attention: Philip M. Haines

IF TO EXECUTIVE:

[•]
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

SANCHEZ MIDSTREAM PARTNERS GP LLC

Dated: August 2, 2019

By: [•]
Name: [•]
Title: [•]

Signature Page to Executive Services Agreement

EXECUTIVE

Dated: August 2, 2019

/s/ [•]

[•]

Signature Page to Executive Services Agreement

Exhibit 31.1

SANCHEZ MIDSTREAM PARTNERS LP
CERTIFICATION

I, Gerry F. Willinger, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Sanchez Midstream Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s Board of Directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 8, 2019

/s/ Gerry F. Willinger
Gerry F. Willinger
Chief Executive Officer
Sanchez Midstream Partners GP, LLC, as general partner of Sanchez Midstream Partners LP
(Principal Executive Officer)

Exhibit 31.2

SANCHEZ MIDSTREAM PARTNERS LP
CERTIFICATION

I, Charles C. Ward, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Sanchez Midstream Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 8, 2019

/s/ Charles C. Ward

Charles C. Ward
Chief Financial Officer and Secretary
Sanchez Midstream Partners GP, LLC, as general partner of Sanchez Midstream Partners LP
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Gerry F. Willinger, Chief Executive Officer of Sanchez Midstream Partners GP, LLC, as general partner of Sanchez Midstream Partners LP, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended June 30, 2019 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Sanchez Midstream Partners LP.

/s/ Gerry F. Willinger

Gerry F. Willinger
Chief Executive Officer
Sanchez Midstream Partners GP, LLC, as general partner of Sanchez Midstream Partners LP
(Principal Executive Officer)

Date: August 8, 2019

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

I, Charles C. Ward, Chief Financial Officer and Secretary of Sanchez Midstream Partners GP, LLC, as general partner of Sanchez Midstream Partners LP, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended June 30, 2019 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Sanchez Midstream Partners LP.

/s/ Charles C. Ward

Charles C. Ward
Chief Financial Officer and Secretary
Sanchez Midstream Partners GP, LLC, as general partner of Sanchez Midstream Partners LP
(Principal Financial Officer)

Date: August 8, 2019