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 September 30, 2020

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.)**
1360 Post Oak Blvd, Suite 2400 **Houston, Texas** **(Address of Principal Executive Offices)**	**77056** **(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(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

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 ☒

Common units outstanding as of November 16, 2020: approximately 19,953,880 common units.

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COMMONLY USED DEFINED TERMS

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

- "Bbl" means one barrel of 42 U.S. gallons of oil or other liquid hydrocarbons.
- "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.
- "Gathering Agreement" means the Firm Gathering and Processing Agreement, dated as of October 14, 2015, by and between Catarina Midstream, LLC and SN Catarina LLC, as amended by Amendment No. 1 thereto, dated June 30, 2017.
- "Manager" refers to SP Holdings, LLC, the sole member of our general partner.
- "MBbl" means one thousand Bbls.
- "MBoe" means one thousand Boe.
- "Mcf" means one thousand cubic feet of natural gas.
- "Mesquite" means (i) at all times prior to June 30, 2020, Sanchez Energy Corporation and its consolidated subsidiaries, and (ii) at all times after and including June 30, 2020, Mesquite Energy, Inc. and its consolidated subsidiaries.
- "MMBtu" means one million British thermal units.
- "MMcf/d" means one million cubic feet of natural gas per day.
- "NGLs" means natural gas liquids such as 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 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.
- "SEC" means the United States Securities and Exchange Commission.
- "Settlement Agreement" means the Settlement Agreement, dated June 6, 2020, as amended by that certain Amendment Agreement, dated as of June 14, 2020 and effective as of June 6, 2020, in each case, by and among the Partnership, our general partner, Catarina Midstream, LLC, Seco Pipeline, LLC, the SN Debtors, Manager, Carnero G&P LLC and TPL SouthTex Processing Company LP.
- "SN Debtors" means collectively, Mesquite, SN Palmetto, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, Rockin L Ranch Company, LLC, SN Payables, LLC, SN EF Maverick, LLC and SN UR Holdings, LLC.
- "SOG" refers to Sanchez Oil & Gas Corporation, an entity that provides operational support to us.

Cautionary Note Regarding Forward-Looking Statements

This Form 10-Q contains “forward-looking statements” within the meaning of the federal securities laws. Except for statements of historical fact, all statements in this Form 10-Q constitute forward-looking statements. Forward-looking statements may be identified by words like “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” the negative of such terms or other similar expressions. The absence of such words or expressions does not necessarily mean the statements are not forward-looking.

The forward-looking statements contained in this Form 10-Q are largely based on our current expectations, which reflect estimates and assumptions made by the management of our general partner. Although we believe such estimates and assumptions to be reasonable, statements made regarding future results are not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that are beyond our control. Actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report. You should not put any undue reliance on any forward-looking statement. All forward-looking information in this Form 10-Q and subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

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

- the resolution of the pending Rejection Lawsuits (as defined below) and their impact on the effectiveness of the Settlement Agreement and our business, results of operations and financial condition;
- our ability to successfully execute our business, acquisition and financing strategies;
- changes in general economic conditions, including market and macro-economic disruptions resulting from the ongoing pandemic caused by a novel strain of coronavirus (“COVID-19”) and related governmental responses;
- 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 extend, replace or refinance our Credit Agreement (as defined below);
- our ability to grow enterprise value;
- the ability of our partners to perform under our joint ventures;
- 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 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, 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.

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 September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Revenues				
Natural gas sales	$ 16	$ 177	$ 334	$ 543
Oil sales	1,755	4,769	9,129	7,841
Natural gas liquid sales	69	115	170	411
Gathering and transportation sales	—	1,720	785	5,105
Gathering and transportation lease revenues	10,670	14,135	34,615	46,361
Total revenues	12,510	20,916	45,033	60,261
Expenses				
Operating expenses				
Lease operating expenses	1,148	2,105	4,389	5,885
Transportation operating expenses	2,198	2,752	7,111	8,476
Production taxes	112	165	262	489
General and administrative expenses	2,693	4,317	10,980	13,237
Unit-based compensation expense	779	271	1,902	1,081
Depreciation, depletion and amortization	5,553	6,441	17,368	19,044
Asset impairments	—	—	23,247	—
Accretion expense	144	132	422	391
Total operating expenses	12,627	16,183	65,681	48,603
Other (income) expense				
Interest expense, net	24,015	12,141	70,188	17,741
Earnings from equity investments	441	(780)	(2,254)	(3,013)
Other income	(2)	(31)	(10)	(98)
Total other expenses	24,454	11,330	67,924	14,630
Total expenses	37,081	27,513	133,605	63,233
Loss before income taxes	(24,571)	(6,597)	(88,572)	(2,972)
Income tax expense	46	213	3	335
Net loss	(24,617)	(6,810)	(88,575)	(3,307)
Less				
Preferred unit paid-in-kind distributions	—	(3,804)	—	(14,409)
Preferred unit distributions	—	—	—	(8,838)
Preferred unit amortization	—	(266)	—	(1,708)
Deemed distribution	—	103,773	—	103,773
Net income (loss) attributable to common unitholders – Basic	(24,617)	92,893	(88,575)	75,511
Mark-to-market on warrant	—	3,097	—	3,097
Net income (loss) attributable to common unitholders – Basic and Diluted	$ (24,617)	$ 95,990	$ (88,575)	$ 78,608
Net income (loss) per unit				
Common units – Basic	$ (1.28)	$ 4.99	$ (4.62)	$ 4.31
Common units – Diluted	$ (1.28)	$ 4.54	$ (4.62)	$ 4.13
Weighted Average Units Outstanding				
Common units – Basic	19,264,636	18,617,385	19,164,245	17,500,886
Common units – Diluted	19,264,636	21,141,065	19,164,245	19,011,877

See accompanying notes to condensed consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	September 30, 2020	December 31, 2019
ASSETS	(Unaudited)	
Current assets		
Cash and cash equivalents	$ 2,192	$ 5,099
Accounts receivable	7,289	133
Accounts receivable – related entities	—	6,719
Prepaid expenses	800	1,193
Fair value of commodity derivative instruments	642	226
Total current assets	10,923	13,370
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	112,471	112,476
Gathering and transportation assets	187,110	186,941
Less: accumulated depreciation, depletion, amortization and impairment	(174,437)	(144,189)
Oil and natural gas properties and equipment, net	125,144	155,228
Other assets		
Intangible assets, net	135,153	145,246
Equity investments	94,941	100,311
Other non-current assets	107	285
Total assets	$ 366,268	$ 414,440
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 4,984	$ 5,347
Accounts payable and accrued liabilities – related entities	—	631
Royalties payable	359	359
Short-term debt, net of debt issuance costs	122,232	39,374
Fair value of commodity derivative instruments	—	985
Total current liabilities	127,575	46,696
Other liabilities		
Long term accrued liabilities – related entities	7,114	4,892
Asset retirement obligation	7,320	6,898
Long-term debt, net of debt issuance costs	—	109,437
Class C preferred units	347,246	281,688
Other liabilities	607	629
Total other liabilities	362,287	403,544
Total liabilities	489,862	450,240
Commitments and contingencies (See Note 11)		
Partners' deficit		
Common units, 19,953,880 and 20,087,462 units issued and outstanding as of September 30, 2020 and December 31, 2019, respectively	(123,594)	(35,800)
Total partners' deficit	(123,594)	(35,800)
Total liabilities and partners' capital	$ 366,268	$ 414,440

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2020	**2019**
Cash flows from operating activities:		
Net loss	$ (88,575)	$ (3,307)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	7,275	8,949
Amortization of debt issuance costs	553	872
Accretion of Class C discount	28,110	5,050
Class C distribution accrual	37,448	7,575
Asset impairments	23,247	—
Accretion expense	422	391
Distributions from equity investments	7,624	12,368
Equity earnings in affiliate	(2,254)	(3,013)
Mark-to-market on warrant	(22)	(3,097)
Net (gain) loss on commodity derivative contracts	(4,008)	2,272
Net cash settlements received on commodity derivative contracts	2,394	813
Unit-based compensation	823	1,081
Gain on earnout derivative	—	(94)
Amortization of intangible assets	10,093	10,095
Changes in Operating Assets and Liabilities:		
Accounts receivable	(6,994)	(23)
Accounts receivable – related entities	6,719	(354)
Prepaid expenses	393	(456)
Other assets	(96)	62
Accounts payable and accrued liabilities	(300)	6,034
Accounts payable and accrued liabilities- related entities	1,591	(925)
Other long-term liabilities	—	53
Net cash provided by operating activities	24,443	44,346
Cash flows from investing activities:		
Development of oil and natural gas properties	5	(131)
Construction of gathering and transportation assets	(182)	(955)
Purchases of and contributions to equity affiliates	—	(242)
Net cash used in investing activities	(177)	(1,328)
Cash flows from financing activities:		
Proceeds from issuance of debt	7,000	—
Repayment of debt	(34,000)	(18,000)
Distributions to common unitholders	—	(5,216)
Class B preferred unit cash distributions	—	(17,675)
Units tendered by SOG employees for tax withholdings	(41)	(218)
Debt issuance costs	(132)	(209)
Net cash used in financing activities	(27,173)	(41,318)
Net decrease in cash and cash equivalents	(2,907)	1,700
Cash and cash equivalents, beginning of period	5,099	2,934
Cash and cash equivalents, end of period	$ 2,192	$ 4,634
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 13	$ 467
Cash paid during the period for income taxes	$ 243	$ 129
Cash paid during the period for interest	$ 4,259	$ 7,404

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, 2019	20,087,462	$ (35,800)	$ (35,800)
Unit-based compensation programs	(23,387)	243	243
Units tendered by SOG employees for tax withholdings	(88,819)	(31)	(31)
Net loss	—	(41,341)	(41,341)
Partners' Deficit, March 31, 2020	19,975,256	(76,929)	(76,929)
Unit-based compensation programs	(126)	266	266
Units tendered by SOG employees for tax withholdings	(19,867)	(11)	(11)
Net loss	—	(22,617)	(22,617)
Partners' Deficit, June 30, 2020	19,955,263	(99,291)	(99,291)
Unit-based compensation programs	(1,383)	314	314
Net loss	—	(24,617)	(24,617)
Partners' Deficit, September 30, 2020	19,953,880	$ (123,594)	$ (123,594)

	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)
Preferred unit exchange	—	103,773	103,773
Unit-based compensation programs	—	271	271
Issuance of common units	901,741	1,839	1,839
Distributions - Class B preferred units	—	(4,070)	(4,070)
Net loss	—	(6,810)	(6,810)
Partners' Capital, September 30, 2019	20,089,827	$ 11,765	$ 11,765

See accompanying notes to condensed consolidated financial statements.

(Unaudited)

1. ORGANIZATION AND BUSINESS

Organization

We are a growth-oriented publicly-traded limited partnership formed in 2005 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, the sole member of our general partner, 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. 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"). The accompanying 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. Midstream includes Western Catarina Midstream (as defined in Note 9 "Intangible Assets"), the Carnero JV (as defined in Note 10 "Investments") and Seco Pipeline (as defined in Note 4 "Fair Value Measurements"). Production 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 and regulations 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, 2019, which was filed with the SEC on March 13, 2020.

Recent Accounting Pronouncements

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

In January 2020, the FASB issued Accounting Standards Update ("ASU") 2020-01 "Investments – Equity Securities (Topic 321), Investments – Equity Method and Joint Ventures (Topic 323), and Derivatives and Hedging (Topic 815)," which clarifies the interaction among the accounting standards for equity securities, equity method investments and certain derivatives. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2020. We are currently in the process of evaluating the impact of adoption of this guidance on our condensed consolidated financial statements.

In August 2018, the FASB issued 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. The Partnership adopted this standard effective January 1, 2020. The adoption of this standard did not have a material impact on our condensed consolidated financial statements.

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. Additionally, in November 2019, the FASB issued ASU 2019-10 “Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates,” which changed the effective date for certain issuers to annual and interim periods in fiscal years beginning after December 15, 2022, and earlier adoption is permitted. We are currently in the process of evaluating the impact of adoption of this guidance 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.

Use of 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. 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 recognized revenue of $12.5 million and $45.0 million for the three and nine months ended September 30, 2020. 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 Firm Transportation Service Agreement, dated September 1, 2017, by and between Seco Pipeline, LLC and SN Catarina, LLC (the “Seco Pipeline Transportation Agreement”) is the only contract that we account for under ASC 606. On January 13, 2020, we received written notice of termination from Mesquite terminating the Seco Pipeline Transportation Agreement effective February 12, 2020. The Gathering Agreement (as defined in Note 12 “Related Party Transactions”) is classified as an operating lease and is accounted for under ASC 842, Leases, and is reported as gathering and transportation lease revenues in our condensed consolidated statements of operations.

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 10 “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 revenues 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 our consolidated statements of operations, which is accounted for under ASC 815, “Derivatives and Hedging.”

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. We applied the series guidance and treated these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. The Seco Pipeline Transportation Agreement required payment within 30 days following the calendar month of delivery.

The Seco Pipeline Transportation Agreement contained 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 our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At September 30, 2020 and December 31, 2019, our accounts receivables from contracts with customers were $1.9 million and $1.1 million, respectively.

4. 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 September 30, 2020 (in thousands):

	Fair Value Measurements at September 30, 2020			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative assets	$ —	$ 642	$ —	$ 642
Other liabilities				
Warrant	—	(607)	—	(607)
Total	$ —	$ 35	$ —	$ 35

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, 2019 (in thousands):

	Fair Value Measurements at December 31, 2019			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative liabilities	$ —	$ (759)	$ —	$ (759)
Other liabilities				
Warrant	—	(629)	—	(629)
Total	$ —	$ (1,388)	$ —	$ (1,388)

As of September 30, 2020 and December 31, 2019, 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 8 "Asset Retirement Obligation."

The following table summarizes the non-recurring fair value measurements of our production assets as of September 30, 2020 (in thousands):

	Fair Value Measurements at September 30, 2020		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment[(a)]	$ —	$ —	$ 12,852
Total net assets	$ —	$ —	$ 12,852

(a) During the nine months ended September 30, 2020, we recorded a non-cash impairment charge of $23.2 million to impair our producing oil and natural gas properties. The carrying values of the impaired properties were reduced to a fair value of $12.9 million, estimated using inputs characteristic of a Level 3 fair value measurement.

We had no non-recurring fair value measurements of our production assets as of December 31, 2019.

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 of 15%. 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.

Class C Preferred Units – On August 2, 2019, as part of the Exchange (as defined in Note 15 "Partners' Capital"), Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and the Warrant (as defined in Note 15 "Partners' Capital") in a private placement transaction. The fair value of the Class C Preferred Units was measured using valuation techniques that convert a future obligation to a single discounted amount. Significant inputs used to determine the fair value were observable and we have therefore classified the fair value measurements of the Class C Preferred units as Level 2.

Seco Pipeline – As of December 31, 2019, we recorded a non-cash impairment charge of $32.1 million to impair a 100% owned and operated 30-mile natural gas pipeline with 400 MMcf/d capacity that is designed and used to transport dry gas from the Raptor Gas Processing Facility to multiple markets in South Texas (the "Seco Pipeline"). The carrying value of the Seco Pipeline was reduced to a fair value of zero, estimated based on inputs characteristic of a Level 3 fair value measurement.

The fair value of the Seco Pipeline was measured using probabilistic valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of the Seco Pipeline include estimates of: (i) future operating and development costs; (ii) estimated future cash flows; 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.

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 (as defined in Note 6 "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 6 "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.

Warrant – As part of the Exchange, the Partnership issued to Stonepeak the Warrant which entitles the holder to receive junior securities representing ten percent of junior securities deemed outstanding when exercised. The Warrant expires on the later of August 2, 2026 or 30 days following the full redemption of the Class C Preferred Units. There is no strike price associated with the exercise of the Warrant. The Warrant is valued using ten percent of the junior securities deemed outstanding and the common unit price as of the balance sheet date. We have therefore classified the fair value measurements of the Warrant as Level 2 and is presented within other liabilities on the condensed consolidated balance sheets.

Earnout Derivative – As part of the Carnero Gathering Transaction (as defined in Note 10 "Investments"), we are required to pay Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite 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 inputs.

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):

	Nine Months Ended September 30, 2020	Year Ended December 31, 2019
Beginning balance	$ —	$ (5,856)
Gain on earnout derivative	—	5,856
Ending balance	$ —	$ —
Gain included in earnings related to derivatives still held as of September 30, 2020 and December 31, 2019, respectively	$ —	$ 5,856

5. 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 September 30, 2020, 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)

	December 31,	
	Volume	Average Price
2020	47,624	$ 53.50

Fixed Price Swaps – NYMEX (Henry Hub)

	December 31,	
	Volume	Average Price
2020	96,200	$ 2.85

The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the nine months ended September 30, 2020 and the year ended December 31, 2019 (in thousands):

	Nine Months Ended September 30, 2020	Year Ended December 31, 2019
Beginning fair value of commodity derivatives	$ (759)	$ 3,914
Net gains (losses) on crude oil derivatives	3,912	(4,031)
Net gains on natural gas derivatives	96	259
Net settlements received on derivative contracts:		
Oil	(2,311)	(807)
Natural gas	(296)	(94)
Ending fair value of commodity derivatives	$ 642	$ (759)

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 September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Commodity – Mark-to-Market	Oil sales	$ (115)	$ 1,195	$ 3,912	$ (2,482)
Commodity – Mark-to-Market	Natural gas sales	(55)	57	96	210
		$ (170)	$ 1,252	$ 4,008	$ (2,272)

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with two 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 September 30, 2020 and December 31, 2019, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Earnout Derivative

Refer to Note 4 “Fair Value Measurements.”

6. DEBT

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto, as amended by the Ninth Amendment to Third Amended and Restated Credit Agreement, dated as of November 22, 2019 (the “Credit Agreement”). The Credit Agreement provides a quarterly amortizing term loan of $155.0 million (the “Term Loan”) and a maximum revolving credit amount of $20.0 million (the “Revolving Loan”). The Term Loan and Revolving Loan both have a maturity date of September 30, 2021. Borrowings under the Credit Agreement are secured by various mortgages of both midstream and upstream properties that we own as well as various security and pledge agreements among us, certain of our subsidiaries and the administrative agent.

The Credit Agreement is a current liability that matures on September 30, 2021. We expect to refinance or extend the maturity of the Credit Agreement prior to its maturity date. However, we may not be able to refinance or extend the maturity of the 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.

Borrowings under the Credit Agreement are available for limited direct investment in oil and natural gas properties, midstream properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of up to $2.5 million which may be used for the issuance of letters of credit. Pursuant to the Credit Agreement, the initial aggregate commitment amount under the Term Loan is $155.0 million, subject to quarterly $10.0 million principal and other mandatory prepayments. The initial borrowing base under the Credit Agreement was $235.5 million. The borrowing base is equal to the sum of the rolling four quarter EBITDA of our midstream operations and the amount of distributions received from the Carnero JV multiplied by 4.5 or a lower number dependent upon natural gas volumes flowing through Western Catarina Midstream. Outstanding borrowings in excess of our borrowing base must be repaid within 45 days. As of September 30, 2020, the borrowing base under the Credit Agreement was $142.1 million and we had $123.0 million of debt outstanding, consisting of $115.0 million under the Term Loan and $8.0 million under the Revolving Loan. We are required to make mandatory amortizing payments of outstanding principal on the Term Loan of $10.0 million per fiscal quarter. The maximum revolving credit amount is $20.0 million leaving us with $12.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of September 30, 2020.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the LIBOR plus an applicable margin between 2.50% and 3.00% per annum based on net debt to EBITDA or (ii) a domestic bank rate (“ABR”) plus an applicable margin between 1.50% and 2.00% per annum based on net debt to EBITDA plus (iii) a commitment fee of 0.500% per annum based on the unutilized maximum revolving credit. 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 to unitholders.

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

- current assets to current liabilities, excluding any current maturities of debt, of at least 1.0 to 1.0 at all times; and
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 3.5 to 1.0.

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.

At September 30, 2020, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

As disclosed in Note 18 “Subsequent Events,” following the end of the quarter ended September 30, 2020 and effective November 6, 2020, the Partnership entered into the Credit Agreement Amendment. Please read Note 18 “Subsequent Events” below for a more detailed description of the Amended Credit Agreement.

Debt Issuance Costs

As of September 30, 2020 and December 31, 2019, our unamortized debt issuance costs were approximately $0.8 million and $1.2 million, respectively. These costs are amortized to interest expense in our condensed consolidated statements of operations over the life of our Credit Agreement. Amortization of debt issuance costs recorded during the three months ended September 30, 2020 and 2019 was approximately $0.2 million and $0.3 million, respectively. Amortization of debt issuance costs recorded during the nine months ended September 30, 2020 and 2019 was approximately $0.6 million and $0.9 million, respectively.

7. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

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

	September 30, 2020	December 31, 2019
Gathering and transportation assets		
Midstream assets	$ 187,110	$ 186,941
Less: Accumulated depreciation, amortization and impairment	(80,067)	(74,648)
Total gathering and transportation assets, net	$ 107,043	$ 112,293

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

	September 30, 2020	December 31, 2019
Oil and natural gas properties and related equipment		
Proved property	$ 112,471	$ 112,476
Less: Accumulated depreciation, depletion, amortization and impairments	(94,370)	(69,541)
Total oil and natural gas properties and equipment, net	$ 18,101	$ 42,935

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 and proved property acquisition costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed 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 five to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 360	$ 1,077	$ 1,856	$ 3,000
Depreciation and amortization of gathering and transportation related assets	1,830	1,999	5,419	5,949
Amortization of intangible assets	3,363	3,365	10,093	10,095
Total Depreciation, depletion and amortization	$ 5,553	$ 6,441	$ 17,368	$ 19,044

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 third-party reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Other 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.

During the nine months ended September 30, 2020, we recorded a non-cash impairment charge of $23.2 million to impair our producing oil and natural gas properties. During the year ended December 31, 2019, we recorded a non-cash impairment charge of $32.1 million to fully impair the Seco Pipeline after receiving the written notice from Mesquite of its intention to terminate the Seco Pipeline Transportation Agreement.

8. 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 AROs 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 nine months ended September 30, 2020 and the year ended December 31, 2019 (in thousands):

	Nine Months Ended September 30, 2020	Year Ended December 31, 2019
Asset retirement obligation, beginning balance	$ 6,898	$ 6,200
Liabilities added from escalating working interests	—	172
Accretion expense	422	526
Asset retirement obligation, ending balance	$ 7,320	$ 6,898

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 nine months ended September 30, 2020 and the year ended December 31, 2019, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs.

9. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance as of September 30, 2020 is related to the Gathering Agreement with Mesquite that was entered into as part of the acquisition of the Western Catarina gathering system. The Western Catarina gathering system ("Western Catarina Midstream") is located on the western portion of Mesquite's acreage position in Dimmit, La Salle and Webb counties, Texas (the western portion of such acreage, "Western Catarina"). Pursuant to the 15-year agreement, Mesquite tenders all of its crude oil, natural gas and other hydrocarbon-based product volumes produced in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15-year life of the agreement.

Amortization expense for each of the nine months ended September 30, 2020 and 2019 was approximately $10.1 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):

	September 30, 2020	December 31, 2019
Beginning balance	$ 145,246	$ 158,706
Amortization	(10,093)	(13,460)
Ending balance	$ 135,153	$ 145,246

10. INVESTMENTS

In July 2016, we completed a transaction pursuant to which we acquired from Mesquite 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 Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite and other producers. See Note 4 "Fair Value Measurements" for further discussion of the earnout derivative.

In November 2016, we completed a transaction pursuant to which we acquired from Mesquite 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 Mesquite and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Mesquite's acreage in Dimmit, Webb, La Salle, Zavala and Maverick counties, Texas (such acreage is collectively referred to as Mesquite's "Comanche Asset") pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Mesquite, which was approved by all of the unaffiliated Comanche Asset 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 September 30, 2020, 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 capital and operating decisions. We have included the investment balance in the equity investments caption on the condensed consolidated balance sheets. For the three months ended September 30, 2020, the Partnership recorded a loss of approximately $0.1 million in equity investments from the Carnero JV, which was compounded by approximately $0.3 million related to the amortization of the contractual customer intangible asset. For the nine months ended September 30, 2020, the Partnership recorded earnings of approximately $3.1 million in equity investments from the Carnero JV, which was offset by approximately $0.9 million related to the amortization of the contractual customer intangible asset. We have included these equity method earnings in the earnings from equity investments line within the condensed consolidated statements of operations. Cash distributions of approximately $7.6 million were received during the nine months ended September 30, 2020.

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

	Nine Months Ended September 30,	
	2020	2019
Sales	$ 55,578	$ 130,588
Total expenses	44,965	118,586
Net income	$ 10,613	$ 12,002

11. COMMITMENTS AND CONTINGENCIES

As part of the Carnero Gathering Transaction, we are required to pay Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite and other producers. This earnout has an approximate value of zero as of September 30, 2020. For the nine months ended September 30, 2020, we made no payments to Mesquite related to the earnout. For the nine months ended September 30, 2019, we paid Mesquite $32.1 thousand related to the earnout.

12. 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, 2019 for a more complete description of certain related party transactions that were entered into prior to 2020. 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 Mesquite pursuant to which Mesquite agreed to tender all of its crude oil, natural gas and other hydrocarbon-based product volumes produced in the Western Catarina area of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the "Gathering Agreement"). During the first five years of the term of the Gathering Agreement, Mesquite is required to meet a minimum quarterly volume delivery commitment of 10,200 Bbls per day of oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. Mesquite is required to pay gathering and processing fees of $0.96 per Bbl for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through Western Catarina Midstream, in each case, subject to an annual escalation for a positive increase in the consumer price index. On June 30, 2017, we and Mesquite amended the Gathering Agreement to add an incremental infrastructure fee to be paid by Mesquite

based on water that is delivered through the gathering system through March 31, 2018 and we and Mesquite subsequently agreed to continue the incremental infrastructure fee on a month-to-month basis.

On June 30, 2020, the SN Debtors emerged from the SN Chapter 11 Case, with Sanchez Energy Corporation becoming a privately held corporation named Mesquite Energy, Inc. As a result, and in accordance with the terms of the Settlement Agreement, we entered into Amendment No. 2 to the Gathering Agreement ("Amendment No. 2") to provide, among other things, (i) a new gathering & processing fee, (ii) removal of the minimum volume commitments and related deficiency fee obligations and (iii) expansion of the dedicated acreage thereunder. Amendment No. 2 will only become effective upon the satisfaction of certain closing conditions (as described in the Settlement Agreement) which have not yet occurred and may not occur at all. As of June 30, 2020, Mesquite is not considered a related party of the Partnership.

As of September 30, 2020 and December 31, 2019, the Partnership also had a net payable of approximately $7.1 million, and $5.5 million, respectively, which are included in the accounts payable and accrued liabilities – related entities and long term accrued liabilities – related entities on the condensed consolidated balance sheets. The payables as of September 30, 2020 and December 31, 2019 consist primarily of obligations for general and administrative costs and costs associated with transportation. The Partnership had a net receivable of zero and approximately $6.7 million as of September 30, 2020 and December 31, 2019, respectively. These amounts are included in accounts receivable – related entities on the condensed consolidated balance sheets and primarily consist of revenues receivable from oil and natural gas production and transportation, offset by costs associated with that production and transportation. Pursuant to the terms of the Settlement Agreement, $1.9 million of past due receivables from Mesquite will be waived by the Partnership, this receivable will be reclassified as a contract asset upon the satisfaction of certain closing conditions (as described in the Settlement Agreement) which have not yet occurred and may not occur at all.

13. 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, 2019	1,155,467	$ 3.86
Vested	(338,840)	5.14
Returned/Cancelled	(133,456)	5.61
Outstanding at September 30, 2020	683,171	$ 2.68

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 September 30, 2020, 974,393 common units remained available for future issuance to participants under the LTIP.

14. DISTRIBUTIONS TO UNITHOLDERS

The table below reflects the payment of cash distributions on common units related to the periods indicated.

Three months ended	Distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2019	$ 0.1500	May 3, 2019	May 22, 2019	May 31, 2019

Beginning with the determination of the distribution for the second-quarter 2019, 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, each quarter since the first-quarter 2019, the Board has determined that the Partnership did not have any available cash and, as a result, no cash distribution has been declared for the common units since the quarter ended March 31, 2019. As previously disclosed, our partnership agreement currently prohibits us from paying any distributions on our common units until we have redeemed all of the Class C Preferred Units. Following such redemption, the Credit Agreement may further limit our ability to pay distributions to unitholders.

The table below reflects the payment of distributions on Class B Preferred Units (defined below) related to the periods indicated.

Three months ended	Cash distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2019	$ 0.28225	May 3, 2019	May 22, 2019	May 31, 2019

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, the Partnership paid a distribution on the Class C Preferred Units in Class C Preferred PIK Units in lieu of a distribution on the Class B Preferred Units for second-quarter 2019.

The table below reflects the payment of distributions on Class C Preferred Units related to the periods indicated.

Three months ended	Class C Preferred PIK distribution	Date of declaration	Date of record	Date of distribution
June 30, 2019	939,327	August 8, 2019	August 20, 2019	August 30, 2019
September 30, 2019	1,007,820	October 30, 2019	November 29, 2019	November 20, 2019
December 31, 2019	1,039,314	February 13, 2020	February 28, 2020	February 20, 2020
March 31, 2020	1,071,793	April 29, 2020	May 20, 2020	May 29, 2020
June 30, 2020	1,105,286	July 31, 2020	August 20, 2020	August 31, 2020

On November 16, 2020, the Partnership and Stonepeak entered into a letter agreement wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The aggregate distribution of 22,274,869 common units (the "Stonepeak Common Distribution Units") is payable to Stonepeak following the satisfaction of certain issuance conditions, including, among other things, the delivery by the Partnership of a fully executed supplemental listing application from the NYSE American approving the issuance of the Stonepeak Common Distribution Units and the compliance by the Partnership and Stonepeak with any applicable federal securities laws applicable to the issuance of the Stonepeak Common Distribution Units. See Note 18 "Subsequent Events" for further discussion of the Stonepeak Common Distribution Units.

15. PARTNERS' CAPITAL

Outstanding Units

As of September 30, 2020, we had no Class B Preferred Units outstanding, 36,474,436 Class C Preferred Units outstanding, and 19,953,880 common units outstanding which included 683,171 unvested restricted common units issued under the LTIP.

Common Unit Issuances

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

Three months ended	Common units	Date of issuance
December 31, 2018	787,750	March 8, 2019
March 31, 2019	887,269	May 23, 2019
June 30, 2019	901,741	August 2, 2019

We entered into a letter agreement with Manager providing that during the period beginning with the fiscal quarter ended September 30, 2019 and continuing until the end of the fiscal quarter after the fiscal quarter in which we redeem all of our issued and outstanding Class C Preferred Units, Manager agrees to delay receipt of its fees, not including reimbursement of costs, as a result, we have not issued any common units to Manager in connection with providing services under the Services Agreement for any quarter following the quarter ended June 30, 2019.

Class B Preferred Unit Offering

On October 14, 2015, pursuant to the Class B Preferred Unit Purchase Agreement dated September 25, 2015, by and 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 private placement 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.

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 "Stonepeak Settlement Agreement") to settle a dispute arising from the calculation of an adjustment to the number of Class B Preferred Units issued. Pursuant to the Stonepeak Settlement Agreement, the Partnership issued 1,704,446 Class B Preferred Units to Stonepeak in a private placement 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.

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

	December 31, 2019
Mezzanine equity, beginning balance	$ 349,857
Amortization of discount	1,708
Distributions	23,247
Distributions paid	(17,675)
Class B Preferred Unit exchange	(357,137)
Mezzanine equity, ending balance	$ —

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 private placement transaction (the "Exchange").

Class C Preferred Units

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.

Under the terms of the Amended Partnership Agreement, commencing with the quarter ended on September 30, 2019, the holders of the Class C Preferred Units receive a quarterly distribution of 12.5% per annum payable in cash. To the extent that Available Cash (as defined in the Amended Partnership Agreement) is insufficient to pay the distribution in cash, all or a portion of the distribution may be paid in Class C Preferred PIK Units. Commencing with the quarter ending March 31, 2022, the distribution rate will increase to 14% per annum. Distributions are to be paid on or about the last day of each of February, May, August and November following the end of each quarter and are charged to interest expense in our condensed consolidated statements of operations.

The Exchange was accounted for as an extinguishment with the difference between the book value of the redeemed instrument and the fair value of the new instrument being considered a deemed contribution to common equity of approximately $103.8 million. The Class C Preferred Units are accounted for as a long-term liability on our condensed consolidated balance sheet consisting of the following (in thousands):

	September 30, 2020	December 31, 2019
Class C Preferred Units, beginning balance	$ 281,688	$ —
Private placement of Class C Preferred Units	—	353,500
Discount	—	(104,250)
Accretion of discount	28,110	13,129
Distribution accrual	37,448	19,309
Class C Preferred Units, ending balance	$ 347,246	$ 281,688

Warrant

On August 2, 2019, in connection with the Exchange, the Partnership issued to Stonepeak the Warrant, which entitles the holder to receive junior securities representing ten percent of junior securities deemed outstanding when exercised. The Warrant expires on the later of August 2, 2026 or 30 days following the full redemption of the Class C Preferred Units. There is no strike price associated with the exercise of the Warrant. The Warrant is accounted for as a liability in accordance with ASC 480 and is presented within other liabilities on the condensed consolidated balance sheet. Changes in the fair value of the Warrant are charged to interest expense in our condensed consolidated statements of operations.

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 Amended 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 Amended 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 Amended 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.

16. 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 natural gas, NGLs and crude oil. 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 September 30,			
	2020		2019	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 16	$ —	$ 177	$ —
Oil sales	1,755	—	4,769	—
Natural gas liquid sales	69	—	115	—
Gathering and transportation sales	—	—	—	1,720
Gathering and transportation lease revenues	—	10,670	—	14,135
Total segment revenues	1,840	10,670	5,061	15,855
Segment operating costs				
Lease operating expenses	891	257	1,636	469
Transportation operating expenses	—	2,198	—	2,752
Production taxes	112	—	165	—
Depreciation, depletion and amortization	360	5,193	1,077	5,364
Accretion expense	55	89	49	83
Total segment operating costs	1,418	7,737	2,927	8,668
Segment other income				
Earnings from equity investments	—	(441)	—	780
Total segment other income	—	(441)	—	780
Segment operating income	$ 422	$ 2,492	$ 2,134	$ 7,967

	Nine Months Ended September 30,			
	2020		2019	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 334	$ —	$ 543	$ —
Oil sales	9,129	—	7,841	—
Natural gas liquid sales	170	—	411	—
Gathering and transportation sales	—	785	—	5,105
Gathering and transportation lease revenues	—	34,615	—	46,361
Total segment revenues	9,633	35,400	8,795	51,466
Segment operating costs				
Lease operating expenses	3,859	530	4,643	1,242
Transportation operating expenses	—	7,111	—	8,476
Production taxes	262	—	489	—
Depreciation, depletion and amortization	1,856	15,512	3,000	16,044
Asset impairments	23,247	—	—	—
Accretion expense	159	263	149	242
Total segment operating costs	29,383	23,416	8,281	26,004
Segment other income				
Earnings from equity investments	—	2,254	—	3,013
Total segment other income	—	2,254	—	3,013
Segment operating income (loss)	$ (19,750)	$ 14,238	$ 514	$ 28,475

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Reconciliation of segment operating income (loss) to net loss				
Total production operating income (loss)	$ 422	$ 2,134	$ (19,750)	$ 514
Total midstream operating income	2,492	7,967	14,238	28,475
Total segment operating income (loss)	2,914	10,101	(5,512)	28,989
General and administrative expenses	(2,693)	(4,317)	(10,980)	(13,237)
Unit-based compensation expense	(779)	(271)	(1,902)	(1,081)
Interest expense, net	(24,015)	(12,141)	(70,188)	(17,741)
Other income	2	31	10	98
Income tax expense	(46)	(213)	(3)	(335)
Net loss	$ (24,617)	$ (6,810)	$ (88,575)	$ (3,307)

The following table summarizes the total assets by operating segment as of September 30, 2020 and December 31, 2019 and total capital expenditures for the nine months ended September 30, 2020 and the year ended December 31, 2019 (in thousands):

	September 30, 2020			
	Production	Midstream	Corporate [a]	Total
Other financial information				
Total assets	$ 21,981	$ 342,449	$ 1,838	$ 366,268
Capital expenditures[b]	$ (5)	$ 182	$ —	$ 177

	December 31, 2019			
	Production	Midstream	Corporate [a]	Total
Other financial information				
Total assets	$ 45,550	$ 362,961	$ 5,929	$ 414,440
Capital expenditures[b]	$ 130	$ 775	$ —	$ 905

(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.

17. 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 $94.9 million.

As of September 30, 2020, 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 our condensed consolidated 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 September 30, 2020 and December 31, 2019 (in thousands):

	September 30, 2020	December 31, 2019
Acquisitions, earnout and capital investments	$ 128,140	$ 128,140
Earnings in equity investments	28,230	25,976
Distributions received	(61,429)	(53,805)
Maximum exposure to loss	$ 94,941	$ 100,311

18. SUBSEQUENT EVENTS

Class C Preferred Unit Distribution in Common Units

On November 11, 2020, 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. Section 5.9(b)(ii) of the Amended Partnership Agreement requires that the quarterly distribution on the Class C Preferred Units be paid in cash, Class C Preferred PIK Units or a combination thereof. On November 16, 2020, the Partnership and Stonepeak entered into a letter agreement (the "Stonepeak Letter Agreement") wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The Stonepeak Letter Agreement also provides that Stonepeak will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the end of such quarter. The Stonepeak Letter Agreement and the transactions completed therein, including the distribution for the three months ended September 30, 2020, (the "Letter Agreement Transactions"), was referred to the Conflicts Committee of the Board. The Conflicts Committee approved the Letter Agreement Transactions, recommended that the Board approve and authorize the execution and performance of the Letter Agreement Transactions, and verified that their approvals constituted "Special Approval" of the Letter Agreement Transactions under and pursuant to the Amended Partnership Agreement. Following the approval and recommendation from the Conflicts Committee, the Board approved the Letter Agreement Transactions. The aggregate distribution of 22,274,869 common units (the "Stonepeak Common Distribution Units") is payable to Stonepeak following the satisfaction of certain issuance conditions, including, among other things, the delivery by the Partnership of a fully executed supplemental listing application from the NYSE American approving the issuance of the Stonepeak Common Distribution Units and the compliance by the Partnership and Stonepeak with any applicable federal securities laws applicable to the issuance of the Stonepeak Common Distribution Units.

Credit Agreement Amendment

On November 6, 2020, the Partnership, as borrower, entered into that certain Tenth Amendment to the Third Amended and Restated Credit Agreement with the guarantors party thereto, Royal Bank of Canada, as administrative agent and collateral agent (the "Agent") and the lenders party thereto (each a "Lender") (the "Credit Agreement Amendment" and the Third Amended and Restated Credit Agreement, as amended by the Tenth Amendment, the "Amended Credit Agreement"). Pursuant to the Credit Agreement Amendment, the parties thereto agreed to, among other things: (a) amend the initial aggregate commitment amount under the first lien revolving credit facility to reduce such amount to $17.5 million, including a further limitation on such amount to $15.0 million through May 14, 2021; (b) amend the conditions precedent to the obligations of any Lender to make a Loan (as defined in the Amended Credit Agreement) to provide that through May 14, 2021, a Borrowing Base Deficiency (as defined in the Amended Credit Agreement) may exist; (c) amend the annual financial statements and annual budget affirmative covenant to provide that the Partnership's audited annual financial statements as reported on by the Partnership's independent public accountants may be delivered with a "going concern" or like qualification or exception, if such qualification or exception results from (i) any actual or prospective breach of the financial covenants set forth in Section 9.01 of the Amended Credit Agreement or (ii) the fact that the final maturity date of any Debt (as defined in the Amended Credit Agreement) is less than one year after the date of such report, and does not otherwise include any qualification or exception as to the scope of such audit; and (d) include a new post-closing covenant requiring the Partnership to either engage an

Advisory Firm (as defined in the Credit Agreement Amendment) or certify that the Partnership has taken material steps, in either case, to implement a strategic transaction generating net cash proceeds reasonably expected to be greater than an amount that will allow the Partnership to repay in full all outstanding obligations under the Loan Documents (as defined in the Amended Credit Agreement) that is anticipated to close by August 31, 2021. The Partnership also agreed to pay fees and expenses of the Agent in connection with the Credit Agreement Amendment (including the reasonable fees, disbursements and other charges of counsel to the Agent).

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 formed in 2005 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 (as each term is defined in Note 10 "Investments" of our Notes to Condensed Consolidated Financial Statements), and reversionary working interests and other production assets in Texas and Louisiana. We have entered into a shared services agreement (the "Services Agreement") with Manager, pursuant to which Manager provides operational services to us including overhead, technical, administrative, marketing, accounting, operation, information systems, financial, compliance, insurance, acquisition, disposition and financing services. 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."

Recent Developments

Stonepeak Transaction

On September 7, 2020, SP Capital Holdings, LLC ("SP Capital"), SP Common Equity LLC ("SPCE"), and Stonepeak Catarina Holdings, LLC ("Stonepeak"), entered into a Contribution and Exchange Agreement (the "Contribution Agreement"), pursuant to which (i) SP Capital contributed 100% of the issued and outstanding membership interest in Manager (the "SP Holdings Contributed Interests") to Stonepeak, (ii) SPCE irrevocably committed to contribute 100 % of the issued and outstanding membership interests in SPCE Sub to Stonepeak, and (iii) as consideration for the contributions, Stonepeak issued 10,000 Class B Units in Stonepeak to SP Capital and 5,000 Class C Units in Stonepeak to SPCE (collectively, the "Stonepeak Transaction"). The Stonepeak Transaction was completed in its entirety on October 5, 2020. In connection with the Stonepeak Transaction, SP Capital, SPCE and Stonepeak entered into that certain Second Amended and Restated Limited Liability Company Agreement of Stonepeak to set forth the respective rights and obligations of the parties with respect to governance and operations of Stonepeak. As a result of the Stonepeak Transaction, a change in control of our general partner and of Manager occurred and, as a result, Stonepeak (i) directly, through the acquisition of the SP Holdings Contributed Interests, owns 100% of Manager, (ii) indirectly, through the acquisition of the SP Holdings Contributed Interests, owns 100% of our general partner, and (iii) indirectly, through our general partner, owns 100% of our general partner interests.

Pursuant to the Amended Partnership Agreement, the general partner conducts, directs and manages all activities of the Partnership under the authority of the Board. Pursuant to the Limited Liability Company Agreement of our general partner, dated March 2, 2015, as amended, Manager appoints all of the members of the Board, other than two directors which Stonepeak is entitled to designate pursuant to that certain Amended and Restated Board Representation and Standstill Agreement, dated as of August 2, 2019 (the "Standstill Agreement").

On October 6, 2020, Amendment No. 8 to Schedule 13D (the "Catarina 13D") was filed on behalf of each of (i) SPCE Sub, (ii) Stonepeak, (iii) Stonepeak Catarina Upper Holdings LLC, (iv) Stonepeak Infrastructure Fund (Orion AIV) LP, (v) Stonepeak Associates LLC, (vi) Stonepeak GP Holdings LP, (vii) Stonepeak GP Investors LLC, (viii) Stonepeak GP Investors Manager LLC, (ix) Michael Dorrell, and (x) Trent Vichie ((ii) through (x), collectively, the "Catarina Reporting Persons") in it was disclosed that Manager began engaging in non-binding discussions with the Board about terminating or, alternatively, amending and restating the Services Agreement. The Services Agreement can be terminated (i) by either party at any time by 180 days' prior written notice to the other party, (ii) by Manager if there is an uncured material breach thereunder by the Partnership, or (iii) by the Partnership, subject to Board approval, if (1) there is an uncured material breach thereunder by Manager or (2) there is a change in control of Manager. Pursuant to the Standstill Agreement, the Partnership must obtain Stonepeak's consent to its termination of the Services Agreement. The Services Agreement provides that if there is a termination other than by either party at the end of the Service Agreement's term, by the Partnership for an uncured breach by Manager, or by the Partnership upon a change of control of Manager, then the Partnership will owe a termination payment to Manager in an amount equal to $5,000,000 plus 5% of the transaction value of all asset acquisitions theretofore consummated. Such termination fee may be payable in cash or common units. If the Partnership terminates upon 180 days' prior notice

then the Partnership must also pay to Manager all costs and expenses of SP Holdings that result from such termination. The Catarina 13D reports that Manager may terminate the Services Agreement upon 180 days' prior written notice to the Partnership and such termination would trigger the Partnership's obligation to pay the termination fee in an amount equal to $5,000,000 plus 5% of the transaction value of all asset acquisitions theretofore consummated. To date, no notice of termination of the Services Agreement has been delivered by Manager, and the Partnership is continuing to discuss the Services Agreement with Manager.

Geophysical Seismic Data Use License Agreement

On September 7, 2020, the Partnership, our general partner, SEP Holdings IV, LLC, a wholly owned subsidiary of the Partnership (such entities, the "License Companies") and Sanchez Oil & Gas Corporation ("SOG") entered into that certain Geophysical Seismic Data Use License Agreement (the "License Agreement"). Pursuant to the License Agreement, SOG has agreed to grant to the License Companies a non-exclusive, royalty-free license (the "License") to use certain seismic, geophysical and geological information ("Data"), including any intellectual property included therein. SOG will deliver copies of the Data, including both digital and hard copy if available, to the License Companies following their written request for records and use pursuant to the License.

The License Agreement will terminate on the earlier of (i) a date designated by our general partner to SOG via written notice, which date can be any time following such notice and which notice can be delivered at any time, and (ii) September 7, 2021.

Under the License Agreement the License Companies agreed to indemnify SOG, its affiliates and their respective equity holders, directors, officers, members, agents or employees (each, an "SOG Party") for losses arising from or relating to (i) any breach of the License Agreement, including misuse and inappropriate disclosure of the Data, to the extent not directly caused by the gross negligence, willful misconduct or fraudulent conduct of any SOG Party, or (ii) any material breach, violation or inaccuracy of any of the License Companies' covenants, representations or warranties under the License Agreement. SOG agreed to indemnify the License Companies and their subsidiaries and affiliates and each of their respective equity holders, managers, officers, unitholders, agents and employees (each, a "Company Party") for losses arising from or relating to (i) an SOG Party's gross negligence, willful misconduct or fraudulent conduct in connection with SOG's grant of the License, or (ii) third party claims arising from or relating to any SOG Party's failure to have valid right, title and interest in and to the Data.

Amendment to Limited Liability Company Agreement of our General Partner

On September 7, 2020, in connection with the Stonepeak Transaction, Manager, as the sole member of our general partner entered into Amendment No. 4 to Limited Liability Company Agreement of our general partner (the "LLC Agreement Amendment") to make certain changes to reflect a reduction in the number of required independent directors on the Board and the audit committee from three to two. In addition, the LLC Agreement Amendment includes the removal of the requirement to have a standing compensation committee and corporate governance committee. The changes to the number of independent directors and committees were made in compliance with the rules and regulations of the NYSE American LLC, which provides that limited partnerships that qualify as smaller reporting companies (such as the Partnership) are required to have an audit committee of at least two members, comprised solely of independent directors.

Changes to the Board and Management

Effective September 8, 2020, Patricio D. Sanchez resigned from his position as President and Chief Operating Officer of our general partner. Mr. Sanchez's resignation was not because of any disagreement with us or our general partner or its management with respect to any matter relating to the operations, policies or practices of us or our general partner.

On September 7, 2020, in connection with the Stonepeak Transaction, (i) Eduardo A. Sanchez and Patricio D. Sanchez resigned from their positions as directors on the Board, and (ii) G.M. Byrd Larberg was removed from his position as a director on the Board in connection with the decrease in the number of required independent directors pursuant to the LLC Agreement Amendment. Messrs. Sanchez did not hold any positions on any committees of the Board. Mr. Larberg was an independent director and was a member of the audit committee and chair of the conflicts committee of the Board.

Also on September 7, 2020, each of John Steen, Michael Bricker and Steven Meisel were appointed to serve as directors on the Board. Each of Messrs. Steen and Bricker waived their right to receive any compensation in connection with their service on the Board, other than reimbursement of out-of-pocket expenses. Messrs. Steen, Bricker and Meisel are not expected to serve on any committees of the Board.

On July 10, 2020, Kirsten A. Hink, the Chief Accounting Officer of our general partner, informed the Board of her resignation to be deemed effective as of June 30, 2020. Ms. Hink's decision to resign from her role as Chief Accounting Officer of our general partner was not due to any disagreement with us, our general partner or the Board, rather it was due to Mesquite's emergence from Chapter 11.

COVID-19

In March 2020, the World Health Organization classified the outbreak of COVID-19 as a pandemic. The pandemic is negatively impacting worldwide economic and commercial activity and financial markets, as well as global demand for petrochemical and petrochemical products. The resulting governmental responses have also resulted in significant business and operational disruptions, including business closures, supply chain disruptions, travel restrictions, stay-at-home orders and limitations on the availability of workforces. As a result, the global economy has been marked by significant slowdown and uncertainty, which has led to a precipitous decline in oil prices in response to demand concerns, further exacerbated by the price war among members of OPEC+ during the first quarter of 2020.

The decline in oil prices has resulted in a significantly weaker outlook for oil and gas producers, including Mesquite. We are dependent on Mesquite as our only current customer for utilization of Western Catarina Midstream, and as our primary customer for utilization of our other midstream assets. The decline in oil prices and impact of the SN Chapter 11 Case have caused a negative impact on our net cash flows during the nine months ended September 30, 2020. If Mesquite should decide to shut-in any of the wells connected to our midstream facilities or otherwise becomes unable to make future payments under the Gathering Agreement, it could have a material and adverse impact on our business. The full extent to which the COVID-19 pandemic impacts our business and operations will depend on the severity, location and duration of the effects and spread of COVID-19, the actions undertaken by national, regional and local governments and health officials to contain the virus or treat its effects, and how quickly and to what extent economic conditions improve and normal business and operating conditions resume. Please read "Part II, Item 1A. Risk Factors."

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

Following 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 Mesquite's acreage position in Dimmit, La Salle and Webb counties, Texas, 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 Mesquite on the acreage dedicated to Western Catarina Midstream, our ability to secure volumes from Mesquite 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. Seco Pipeline throughput volumes are dependent on gas processed at the Raptor Gas Processing Facility and demand for dry gas in markets in South Texas.

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 midstream 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 Form 10-Q. 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 loss, its most directly comparable GAAP performance measure, for each of the periods presented (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Net loss	$ (24,617)	$ (6,810)	$ (88,575)	$ (3,307)
Adjusted by:				
Interest expense, net	24,015	12,141	70,188	17,741
Income tax expense	46	213	3	335
Depreciation, depletion and amortization	5,553	6,441	17,368	19,044
Asset impairments	—	—	23,247	—
Accretion expense	144	132	422	391
Unit-based compensation expense	779	271	1,902	1,081
Unit-based asset management fees	260	1,922	2,221	5,793
Distributions in excess of equity earnings	8,084	4,079	11,398	9,555
(Gain) loss on mark-to-market activities	875	(985)	(1,401)	2,844
Adjusted EBITDA	$ 15,139	$ 17,404	$ 36,773	$ 53,477

Significant Operational Factors

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Western Catarina Midstream:				
Oil (MBbls/d)	7.0	9.7	7.6	11.8
Natural gas (MMcf/d)	92.2	122.3	96.6	139.0
Water (MBbls/d)	3.1	4.2	3.3	6.1
Seco Pipeline:				
Natural gas (MMcf/d)	—	—	0.1	2.5

Production. Our production for the three months ended September 30, 2020, was 62 MBoe, or an average of 674 Boe/d, compared to approximately 85 MBoe, or an average of 924 Boe/d, for the three months ended September 30, 2019. Our production for the nine

months ended September 30, 2020, was 183 MBoe, or an average of 668 Boe/d, compared to approximately 236 MBoe, or an average of 864 Boe/d, for the nine months ended September 30, 2019.

Hedging Activities. For the three months ended September 30, 2020, the non-cash mark-to-market loss for our commodity derivatives was approximately $0.9 million, compared to a gain of approximately $1.0 million for the same period in 2019. For the nine months ended September 30, 2020, the non-cash mark-to-market gain for our commodity derivatives was approximately $1.4 million, compared to a loss of approximately $2.9 million for the nine months ended September 30, 2019.

Subsequent Events

Class C Preferred Unit Distribution in Common Units

On November 11, 2020, 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. Section 5.9(b)(ii) of the Amended Partnership Agreement requires that the quarterly distribution on the Class C Preferred Units be paid in cash, Class C Preferred PIK Units or a combination thereof. On November 16, 2020, the Partnership and Stonepeak entered into a letter agreement (the "Stonepeak Letter Agreement") wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The Stonepeak Letter Agreement also provides that Stonepeak will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the end of such quarter. The Stonepeak Letter Agreement and the transactions completed therein, including the distribution for the three months ended September 30, 2020 (the "Letter Agreement Transactions"), was referred to the Conflicts Committee of the Board. The Conflicts Committee approved the Letter Agreement Transactions, recommended that the Board approve and authorize the execution and performance of the Letter Agreement Transactions, and verified that their approvals constituted "Special Approval" of the Letter Agreement Transactions under and pursuant to the Amended Partnership Agreement. Following the approval and recommendation from the Conflicts Committee, the Board approved the Letter Agreement Transactions. The aggregate distribution of 22,274,869 common units (the "Stonepeak Common Distribution Units") is payable to Stonepeak following the satisfaction of certain issuance conditions, including, among other things, the delivery by the Partnership of a fully executed supplemental listing application from the NYSE American approving the issuance of the Stonepeak Common Distribution Units and the compliance by the Partnership and Stonepeak with any applicable federal securities laws applicable to the issuance of the Stonepeak Common Distribution Units.

Credit Agreement Amendment

On November 6, 2020, the Partnership, as borrower, entered into that certain Tenth Amendment to Third Amended and Restated Credit Agreement with the guarantors party thereto, Royal Bank of Canada, as administrative agent and collateral agent (the "Agent") and the lenders party thereto (each a "Lender") (the "Credit Agreement Amendment" and the Third Amended and Restated Credit Agreement, as amended by the Tenth Amendment, the "Amended Credit Agreement"). Pursuant to the Credit Agreement Amendment, the parties agreed to, among other things: (a) amend the initial aggregate commitment amount under the first lien revolving credit facility to reduce such amount to $17.5 million, including a further limitation on such amount to $15.0 million through May 14, 2021; (b) amend the conditions precedent to the obligations of any Lender to make a Loan (as defined in the Amended Credit Agreement) to provide that through May 14, 2021, a Borrowing Base Deficiency (as defined in the Amended Credit Agreement) may exist; (c) amend the annual financial statements and annual budget affirmative covenant to provide that the Partnership's audited annual financial statements as reported on by the Partnership's independent public accountants may be delivered with a "going concern" or like qualification or exception, if such qualification or exception results from (i) any actual or prospective breach of the financial covenants set forth in Section 9.01 of the Amended Credit Agreement or (ii) the fact that the final maturity date of any Debt (as defined in the Amended Credit Agreement) is less than one year after the date of such report, and does not otherwise include any qualification or exception as to the scope of such audit; and (d) include a new post-closing covenant requiring the Partnership to either engage an Advisory Firm (as defined in the Credit Agreement Amendment) or certify that the Partnership has taken material steps in either case, to implement a strategic transaction generating net cash proceeds reasonably expected to be greater than an amount that will allow the Partnership to repay in full all outstanding obligations under the Loan Documents (as defined in the Amended Credit Agreement) that is anticipated to close by August 31, 2021. The Partnership also agreed to pay fees and expenses of the Agent in connection with the Credit Agreement Amendment (including the reasonable fees, disbursements and other charges of counsel to the Agent).

Results of Operations by Segment

Three months ended September 30, 2020 compared to three months ended September 30, 2019

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 September 30,			
	2020	2019	Variance	
Revenues:				
Gathering and transportation sales	$ —	$ 1,720	$ (1,720)	(100%)
Gathering and transportation lease revenues	10,670	14,135	(3,465)	(25%)
Total gathering and transportation sales	10,670	15,855	(5,185)	(33%)
Operating expenses:				
Lease operating expenses	257	469	(212)	(45%)
Transportation operating expenses	2,198	2,752	(554)	(20%)
Depreciation and amortization	5,193	5,364	(171)	(3%)
Accretion expense	89	83	6	7%
Total operating expenses	7,737	8,668	(931)	(11%)
Other income:				
Earnings from equity investments	(441)	780	(1,221)	NM [(a)]
Operating income	$ 2,492	$ 7,967	$ (5,475)	(69%)

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

Gathering and transportation sales. Gathering and transportation sales decreased approximately $1.7 million, or 100%, to zero for the three months ended September 30, 2020. This decrease was the result of the termination of the Seco Pipeline Transportation Agreement, which was effective February 12, 2020.

Gathering and transportation lease revenues. Gathering and transportation lease revenues decreased approximately $3.5 million, or 25%, to approximately $10.7 million for the three months ended September 30, 2020, compared to approximately $14.1 million for the same period in 2019. This decrease was primarily the result of a decrease in overall volumes being transported through Western Catarina Midstream under the Gathering Agreement.

Lease operating expenses. Lease operating expenses, which include ad valorem taxes, decreased approximately $0.2 million, or 45%, to approximately $0.3 million for the three months ended September 30, 2020, compared to approximately $0.5 million during the same period in 2019. This decrease was primarily the result of reduced ad valorem taxes associated with the Seco Pipeline.

Transportation operating expenses. Our transportation 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 by approximately $0.6 million, or 20%, to approximately $2.2 million for the three months ended September 30, 2020 compared to approximately $2.8 million for the same period in 2019. This decrease was due to the nature of operating expenses being dependent on throughput.

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 five to 15 years for equipment and up to 36 years for gathering facilities. Our depreciation and amortization expense decreased slightly by approximately $0.2 million, or 3%, to approximately $5.2 million for the three months ended September 30, 2020 compared to approximately $5.4 million for the same period in 2019.

Earnings from equity investments. Earnings from equity investments decreased approximately $1.2 million, or 157%, to a loss of approximately $0.4 million for the three months ended September 30, 2020, compared to earnings of approximately $0.8 million for the same period in 2019. This decrease was primarily the result of lower throughput during the three months ended September 30, 2020.

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 September 30,			
	2020	2019	Variance	
Revenues:				
Natural gas sales at market price	$ 71	$ 120	$ (49)	(41%)
Natural gas hedge settlements	86	69	17	NM [(a)]
Natural gas mark-to-market activities	(141)	(12)	(129)	NM [(a)]
Natural gas total	16	177	(161)	(91%)
Oil sales at market price	1,870	3,574	(1,704)	(48%)
Oil hedge settlements	619	229	390	NM [(a)]
Oil mark-to-market activities	(734)	966	(1,700)	NM [(a)]
Oil total	1,755	4,769	(3,014)	NM [(a)]
NGL sales	69	115	(46)	(40%)
Total revenues	1,840	5,061	(3,221)	NM [(a)]
Operating expenses:				
Lease operating expenses	891	1,636	(745)	(46%)
Production taxes	112	165	(53)	(32%)
Depreciation, depletion and amortization	360	1,077	(717)	(67%)
Accretion expense	55	49	6	12%
Total operating expenses	1,418	2,927	(1,509)	(52%)
Operating income	$ 422	$ 2,134	$ (1,712)	NM [(a)]

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

	Three Months Ended September 30,			
	2020	2019	Variance	
Net production:				
Natural gas (MMcf)	39	79	(40)	(51%)
Oil production (MBbl)	49	60	(11)	(18%)
NGLs (MBbl)	6	12	(6)	(50%)
Total production (MBoe)	62	85	(23)	(27%)
Average daily production (Boe/d)	674	924	(250)	(27%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 4.03	$ 2.39	$ 1.64	69%
Natural gas price per Mcf without hedge settlements	$ 1.82	$ 1.52	$ 0.30	20%
Oil price per Bbl with hedge settlements	$ 50.80	$ 63.38	$ (12.58)	(20%)
Oil price per Bbl without hedge settlements	$ 38.16	$ 59.57	$ (21.41)	(36%)
NGL price per Bbl without hedge settlements	$ 11.50	$ 9.58	$ 1.92	20%
Total price per Boe with hedge settlements	$ 43.79	$ 48.32	$ (4.53)	(9%)
Total price per Boe without hedge settlements	$ 32.42	$ 44.81	$ (12.39)	(28%)
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 16.18	$ 21.19	$ (5.01)	(24%)
Lease operating expenses	$ 14.37	$ 19.25	$ (4.88)	(25%)
Production taxes	$ 1.81	$ 1.94	$ (0.13)	(7%)
Depreciation, depletion and amortization	$ 5.81	$ 12.67	$ (6.86)	(54%)

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

Production. For the three months ended September 30, 2020, 79% of our production was oil, 11% was NGLs and 10% was natural gas as compared to the three months ended September 30, 2019, when 71% of our production was oil, 14% was NGLs and 15% was natural gas. The production mix between the periods has remained largely consistent. Combined production decreased by 23 MBoe for the three months ended September 30, 2020. This decrease was due to temporarily shutting in some wells while drilling occurred in the area.

Sales of natural gas, NGLs and oil. Unhedged oil sales decreased approximately $1.7 million, or 48%, to approximately $1.9 million for the three months ended September 30, 2020, compared to approximately $3.6 million for the same period in 2019. NGL and unhedged natural gas sales remained relatively consistent for the three months ended September 30, 2020, with no material change when compared to the same period in 2019. The total decrease in oil, natural gas and NGL sales for the three months ended September 30, 2020 were primarily the result of lower realized commodity prices and decreases in production.

Including hedges and mark-to-market activities, our total production-related revenue decreased approximately $3.2 million for the three months ended September 30, 2020, compared to the same period in 2019. This decrease was primarily the result of an approximately $1.8 million loss on oil and natural gas mark-to-market activities and a decrease of approximately $1.7 million in unhedged oil sales offset by an increase of approximately $0.4 million in oil and natural gas hedge settlements.

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 September 30, 2019 to the three months ended September 30, 2020 (dollars in thousands, except average sales prices and volumes):

	Q3 2020 Production Volume	Q3 2019 Production Volume	Production Volume Difference	Q3 2019 Average Sales Price	Revenue Decrease due to Production
Natural gas (MMcf)	39	79	(40)	$ 1.52	$ (61)
Oil (MBbl)	49	60	(11)	$ 59.57	$ (655)
NGLs (MBbl)	6	12	(6)	$ 9.58	$ (57)
Total oil equivalent (MBoe)	62	85	(23)	$ 44.81	$ (773)

	Q3 2020 Average Sales Price	Q3 2019 Average Sales Price	Average Sales Price Difference	Q3 2020 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 1.82	$ 1.52	$ 0.30	39	$ 12
Oil (MBbl)	$ 38.16	$ 59.57	$ (21.41)	49	$ (1,049)
NGLs (MBbl)	$ 11.50	$ 9.58	$ 1.92	6	$ 12
Total oil equivalent (MBoe)	$ 32.42	$ 44.81	$ (12.39)	62	$ (1,025)

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 September 30, 2020 by approximately $0.2 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the three months ended September 30, 2020, the non-cash mark-to-market loss was approximately $0.9 million, compared to a gain of approximately $1.0 million for the same period in 2019. The 2020 non-cash loss resulted from higher future expected oil prices on these derivative transactions. Cash settlements received for our commodity derivative contracts were approximately $0.7 million for the three months ended September 30, 2020, compared to cash settlements received of approximately $0.3 million for the three months ended September 30, 2019.

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 $0.7 million, or 46%, to approximately $0.9 million for the three months ended September 30, 2020, compared to approximately $1.6 million for the same period in 2019. This decrease was primarily the result of reduced workover activity during the three months ended September 30, 2020 compared to the same period in 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 September 30, 2020 decreased approximately $0.7 million, or 67%, to approximately $0.4 million, compared to approximately $1.1 million for the same period in 2019. This decrease is primarily the result of reduced depletion from the $23.2 million proved property impairment charge taken in the first quarter 2020.

Consolidated Earnings Results

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

	Three Months Ended September 30,			
	2020	2019	Variance	
Reconciliation of segment operating income to net loss				
Total production operating income	$ 422	$ 2,134	$ (1,712)	NM [a]
Total midstream operating income	2,492	7,967	(5,475)	(69%)
Total segment operating income	2,914	10,101	(7,187)	(71%)
General and administrative expenses	(2,693)	(4,317)	1,624	(38%)
Unit-based compensation expense	(779)	(271)	(508)	NM [a]
Interest expense, net	(24,015)	(12,141)	(11,874)	98%
Other income	2	31	(29)	(94%)
Income tax expense	(46)	(213)	167	NM [a]
Net loss	$ (24,617)	$ (6,810)	$ (17,807)	NM [a]

(b) 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 $1.1 million, or 24%, to approximately $3.4 million for the three months ended September 30, 2020 compared to approximately $4.6 million for the same period in 2019. The decrease was primarily the result of a reduction in asset management fee charges under the Services Agreement due to a decline in the value of certain assets.

Interest expense, net. Interest expense consists of distributions on the Class C Preferred Units, non-cash accretion of the discount on the Class C Preferred Units, the non-cash change in fair value of the Warrant (as defined in Note 15 "Partners' Capital" of our Notes to Condensed Consolidated Financial Statements) and cash interest expense from borrowings under the Credit Agreement. Interest expense increased approximately $11.9 million, or 98%, to approximately $24.0 million for the three months ended September 30, 2020 compared to approximately $12.1 million for the same period in 2019. This increase was the result of the Class C Preferred Units and the Warrant being issued on August 2, 2019 and the corresponding GAAP requirement that the accrual of distributions on the Class C Preferred Units and mark-to-market impact of the Warrant be classified as charges to interest expense. Cash interest expense for the three months ended September 30, 2020 was approximately $1.1 million compared to approximately $2.3 million for the same period in 2019. The decrease in cash interest expense was primarily the result of the decrease in the outstanding Credit Agreement debt balance between the periods.

Income tax expense. Income tax expense was approximately $45.7 thousand for the three months ended September 30, 2020, compared to an expense of approximately $213.1 thousand for the same period in 2019. The decrease resulted from income taxes on gross margin within the state of Texas, which was primarily driven by a decrease in total operating revenues over the comparable periods.

Nine months ended September 30, 2020 compared to nine months ended September 30, 2019

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):

	Nine Months Ended September 30,			
	2020	2019	Variance	
Revenues:				
Gathering and transportation sales	$ 785	$ 5,105	$ (4,320)	(85%)
Gathering and transportation lease revenues	34,615	46,361	(11,746)	(25%)
Total gathering and transportation sales	35,400	51,466	(16,066)	(31%)
Operating costs:				
Lease operating expenses	530	1,242	(712)	(57%)
Transportation operating expenses	7,111	8,476	(1,365)	(16%)
Depreciation and amortization	15,512	16,044	(532)	(3%)
Accretion expense	263	242	21	9%
Total operating expenses	23,416	26,004	(2,588)	(10%)
Other income:				
Earnings from equity investments	2,254	3,013	(759)	(25%)
Operating income	$ 14,238	$ 28,475	$ (14,237)	(50%)

Gathering and transportation sales. Gathering and transportation sales decreased approximately $4.3 million, or 85%, to approximately $0.8 million for the nine months ended September 30, 2020, compared to approximately $5.1 million for the same period in 2019. This decrease was the result of the termination of the Seco Pipeline Transportation Agreement, which was effective February 12, 2020.

Gathering and transportation lease revenues. Gathering and transportation lease revenues decreased approximately $11.7 million, or 25%, to approximately $34.6 million for the nine months ended September 30, 2020, compared to approximately $46.3 million for the same period in 2019. This decrease was primarily the result of a decrease in overall volumes being transported through Western Catarina Midstream under the Gathering Agreement.

Lease operating expenses. Lease operating expenses, which include ad valorem taxes, decreased approximately $0.7 million, or 57%, to approximately $0.5 million for the nine months ended September 30, 2020, compared to approximately $1.2 million during the same period in 2019. This decrease was due to lower throughput during the period.

Transportation operating expenses. Our transportation 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 approximately $1.4 million, or 16%, to approximately $7.1 million for the nine months ended September 30, 2020 compared to approximately $8.5 million for the same period in 2019. This decrease was due to lower throughput during the period.

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 five to 15 years for equipment and up to 36 years for gathering facilities. Our depreciation and amortization expense decreased slightly by approximately $0.5 million, or 3%, to approximately $15.5 million for the nine months ended September 30, 2020 compared to approximately $16.0 million for the same period in 2019.

Earnings from equity investments. Earnings from equity investments decreased approximately $0.8 million, or 25%, to approximately $2.2 million for the nine months ended September 30, 2020, compared to earnings of approximately $3.0 million for the same period in 2019. This decrease was primarily the result of lower throughput during the nine months ended September 30, 2020.

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):

	Nine Months Ended September 30,			
	2020	2019	Variance	
Revenues:				
Natural gas sales at market price	$ 238	$ 333	$ (95)	(29%)
Natural gas hedge settlements	296	56	240	NM [(a)]
Natural gas mark-to-market activities	(200)	154	(354)	NM [(a)]
Natural gas total	334	543	(209)	(38%)
Oil sales	5,217	10,323	(5,106)	(49%)
Oil hedge settlements	2,311	610	1,701	NM [(a)]
Oil mark-to-market activities	1,601	(3,092)	4,693	NM [(a)]
Oil total	9,129	7,841	1,288	16%
NGL sales	170	411	(241)	(59%)
Total revenues	9,633	8,795	838	10%
Operating costs:				
Lease operating expenses	3,859	4,643	(784)	(17%)
Production taxes	262	489	(227)	(46%)
Depreciation, depletion and amortization	1,856	3,000	(1,144)	(38%)
Asset impairments	23,247	—	23,247	NM [(a)]
Accretion expense	159	149	10	7%
Total operating expenses	29,383	8,281	21,102	NM (a)
Operating income (loss)	$ (19,750)	$ 514	$ (20,264)	NM [(a)]

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

	Nine Months Ended September 30,			
	2020	2019	Variance	
Net production:				
Natural gas (MMcf)	119	178	(59)	(33%)
Oil production (MBbl)	145	173	(28)	(16%)
NGLs (MBbl)	18	33	(15)	(45%)
Total production (MBoe)	183	236	(53)	(22%)
Average daily production (Boe/d)	668	864	(196)	(23%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 4.49	$ 2.19	$ 2.30	105%
Natural gas price per Mcf without hedge settlements	$ 2.00	$ 1.87	$ 0.13	7%
Oil price per Bbl with hedge settlements	$ 51.92	$ 63.20	$ (11.28)	(18%)
Oil price per Bbl without hedge settlements	$ 35.98	$ 59.67	$ (23.69)	(40%)
NGL price per Bbl without hedge settlements	$ 9.44	$ 12.45	$ (3.01)	(24%)
Total price per Boe with hedge settlements	$ 44.98	$ 49.72	$ (4.74)	(10%)
Total price per Boe without hedge settlements	$ 30.74	$ 46.89	$ (16.15)	(34%)
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 22.52	$ 21.75	$ 0.77	4%
Lease operating expenses	$ 21.09	$ 19.67	$ 1.42	7%
Production taxes	$ 1.43	$ 2.07	$ (0.64)	(31%)
Depreciation, depletion and amortization	$ 10.14	$ 12.71	$ (2.57)	(20%)

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

Production. For the nine months ended September 30, 2020, 79% of our production was oil, 10% was NGLs and 11% was natural gas as compared to the nine months ended September 30, 2019, when 73% of our production was oil, 14% was NGLs and 13% was natural gas. The production mix between the periods has remained largely consistent. Combined production decreased by 53 MBoe for the nine months ended September 30, 2020, primarily due to workovers and temporarily shutting in some wells production while drilling occurred in the area.

Sales of natural gas, NGLs and oil. Unhedged oil sales decreased approximately $5.1 million, or 49%, to approximately $5.2 million for the nine months ended September 30, 2020, compared to approximately $10.3 million for the same period in 2019. NGL and unhedged natural gas sales remained relatively consistent for the nine months ended September 30, 2020 and 2019. Total decreases in

oil, natural gas and NGL sales for the nine months ended September 30, 2020 were primarily the result of lower realized commodity prices and decreases in production for the same factors described under “Production” above.

Including hedges and mark-to-market activities, our total production-related revenue increased approximately $0.8 million for the nine months ended September 30, 2020, compared to the same period in 2019. This increase was primarily the result of increases of approximately $4.3 million in oil and natural gas mark-to-market activities and approximately $1.9 million in settlements on oil and natural gas derivatives, offset by a decrease of approximately $5.1 million in oil 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 nine months ended September 30, 2019 to the nine months ended September 30, 2020 (dollars in thousands, except average sales prices and volumes):

	2020 Production Volume	2019 Production Volume	Production Volume Difference	2019 Average Sales Price	Revenue Decrease due to Production
Natural gas (MMcf)	119	178	(59)	$ 1.87	$ (110)
Oil (MBbl)	145	173	(28)	$ 59.67	$ (1,671)
NGLs (MBbl)	18	33	(15)	$ 12.45	$ (187)
Total oil equivalent (MBoe)	183	236	(53)	$ 46.89	$ (1,968)

	2020 Average Sales Price	2019 Average Sales Price	Average Sales Price Difference	2020 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 2.00	$ 1.87	$ 0.13	119	$ 15
Oil (MBbl)	$ 35.98	$ 59.67	$ (23.69)	145	$ (3,435)
NGLs (MBbl)	$ 9.44	$ 12.45	$ (3.01)	18	$ (54)
Total oil equivalent (MBoe)	$ 30.74	$ 46.89	$ (16.15)	183	$ (3,474)

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 nine months ended September 30, 2020 by approximately $0.6 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the nine months ended September 30, 2020, the non-cash mark-to-market gain was approximately $1.4 million, compared to a loss of approximately $2.9 million for the same period in 2019. The 2020 non-cash gain resulted from lower future expected oil prices on these derivative transactions. Cash settlements received for our commodity derivative contracts were approximately $2.6 million for the nine months ended September 30, 2020, compared to cash settlements received of approximately $0.7 million for the nine months ended September 30, 2019.

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 $0.8 million, or 17%, to approximately $3.9 million for the nine months ended September 30, 2020, compared to approximately $4.6 million during the same period in 2019. This decrease was primarily the result of reduced workover activity during the nine months ended September 30, 2020 compared to the same period in 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 nine months ended September 30, 2020 decreased approximately $1.1 million, or 38%, to approximately $1.9 million, compared to approximately $3.0 million for the same period in 2019. This decrease is primarily the result of reduced depletion from the $23.2 million proved property impairment charge taken in the first quarter 2020.

Impairment expense. For the nine months ended September 30, 2020, our non-cash proved property impairment charge was approximately $23.2 million. We did not record impairment charges for the nine months ended September 30, 2019.

Consolidated Earnings Results

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

	Nine Months Ended September 30,			
	2020	2019	Variance	
Reconciliation of segment operating income (loss) to net income (loss)				
Total production operating income (loss)	$ (19,750)	$ 514	$ (20,264)	NM [a]
Total midstream operating income	14,238	28,475	(14,237)	(50%)
Total segment operating income (loss)	(5,512)	28,989	(34,501)	NM (a)
General and administrative expenses	(10,980)	(13,237)	2,257	(17%)
Unit-based compensation expense	(1,902)	(1,081)	(821)	76%
Interest expense, net	(70,188)	(17,741)	(52,447)	NM [a]
Other income	10	98	(88)	(90%)
Income tax benefit (expense)	(3)	(335)	332	NM (a)
Net loss	$ (88,575)	$ (3,307)	$ (85,268)	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 $1.4 million, or 10%, to approximately $12.9 million for the nine months ended September 30, 2020 compared to approximately $14.3 million for the same period in 2019. The decrease was primarily the result of reductions in asset management fee charges under the Services Agreement due to a decline in the value of certain assets.

Interest expense, net. Interest expense consists of distributions on the Class C Preferred Units, non-cash accretion of the discount on the Class C Preferred Units, the non-cash change in fair value of the Warrant and cash interest expense from borrowings under the Credit Agreement. Interest expense increased approximately $52.4 million to approximately $70.2 million for the nine months ended September 30, 2020 compared to approximately $17.7 million for the same period in 2019. This increase was the result of the Class C Preferred Units and the Warrant being issued on August 2, 2019 and the corresponding GAAP requirement that the accrual of distributions on the Class C Preferred Units and mark-to-market impact of the Warrant be classified as charges to interest expense. Cash interest expense for the nine months ended September 30, 2020 was approximately $4.1 million compared to approximately $7.3 million for the same period in 2019. The decrease in cash interest expense was primarily the result of the decrease in the outstanding Credit Agreement debt balance between the periods.

Income tax benefit. Income tax expense was approximately $2.9 thousand for the nine months ended September 30, 2020, compared to an expense of approximately $335.0 thousand for the same period in 2019. The decrease resulted from income taxes on gross margin within the state of Texas, which was primarily driven by a decrease in total operating revenues over the comparable periods.

Liquidity and Capital Resources

As of September 30, 2020, we had approximately $2.2 million in cash and cash equivalents and $12.0 million available for borrowing under the Credit Agreement, as discussed further below.

During the three months ended September 30, 2020, we paid approximately $1.0 million in cash for interest on borrowings under our Credit Agreement, of which approximately $18.8 thousand was related to the fee on undrawn commitments. During the nine months ended September 30, 2020, we paid approximately $4.3 million in cash for interest on borrowings under our Credit Agreement, of which approximately $56.0 thousand was related to the fee on undrawn commitments.

Our capital expenditures during the nine months ended September 30, 2020 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 common units or other limited partner interests. 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, when we are eligible to resume cash distributions under the terms of our Amended Partnership Agreement and our Credit Agreement, quarterly cash distributions to unitholders.

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

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto as amended by the Credit Agreement Amendment (the "Credit Agreement"). The Credit Agreement provides a quarterly amortizing term loan of $155.0 million (the "Term Loan") and a maximum revolving credit amount of $20.0 million (the "Revolving Loan"). The Term Loan and Revolving Loan both have a maturity date of September 30, 2021. Borrowings under the Credit Agreement are secured by various mortgages of both midstream and upstream properties that we own as well as various security and pledge agreements among us, certain of our subsidiaries and the administrative agent.

The Credit Agreement is a current liability that matures on September 30, 2021. We expect to refinance or extend the maturity of the Credit Agreement prior to its maturity date. However, we may not be able to refinance or extend the maturity of the 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.

Borrowings under the Credit Agreement are available for limited direct investment in oil and natural gas properties, midstream properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of up to $2.5 million which may be used for the issuance of letters of credit. Pursuant to the Credit Agreement, the initial aggregate commitment amount under the Term Loan is $155.0 million, subject to quarterly $10.0 million principal and other mandatory prepayments. The borrowing base is equal to the sum of the rolling four quarter EBITDA of our midstream operations and the amount of distributions received from the Carnero JV multiplied by 4.5 or a lower number dependent upon natural gas volumes flowing through Western Catarina Midstream. Outstanding borrowings in excess of our borrowing base must be repaid within 45 days. As of September 30, 2020, the borrowing base under the Credit Agreement was $142.1 million and we had $123.0 million of debt outstanding, consisting of $115.0 million under the Term Loan and $8.0 million under the Revolving Loan. We are required to make mandatory payments of outstanding principal on the Term Loan of $10.0 million per fiscal quarter. The maximum revolving credit amount is $20.0 million which left us with $12.0 million in unused borrowing capacity at September 30, 2020. There were no letters of credit outstanding under our Credit Agreement as of September 30, 2020.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank offered rate ("LIBOR") plus an applicable margin between 2.50% and 3.00% per annum based on net debt to EBITDA or (ii) a domestic bank rate ("ABR") plus an applicable margin between 1.50% and 2.00% per annum based on net debt to EBITDA plus (iii) a commitment fee of 0.500% per annum based on the unutilized maximum revolving credit. 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 excluding any current maturities of debt, of at least 1.0 to 1.0 at all times; and
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 3.5 to 1.0.

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.

Our Amended Partnership Agreement prohibits us from paying any distributions on our common units until we have redeemed all of the Class C Preferred Units. Following such redemption, the Credit Agreement further limits our ability to pay distributions to unitholders.

At September 30, 2020, 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 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.

As disclosed above, following the end of the quarter ended September 30, 2020, and effective November 6, 2020, we entered into the Credit Agreement Amendment. Please read "—Subsequent Events—Credit Agreement Amendment" above for a more detailed description of the Amended Credit Agreement.

Sources of Debt and Equity Financing

As of September 30, 2020, we had $8.0 million of debt outstanding under the Revolving Loan, leaving us with $12.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of September 30, 2020. Our Credit Agreement matures on September 30, 2021.

Open Commodity Hedge Positions

We periodically 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 projected 2020 oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flows. 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 2020 production without posting cash collateral based on price changes prior to the hedges being cash settled.

The following tables as of September 30, 2020, 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)

	December 31,			
	Volume		Average Price	
2020	47,624		$	53.50

MTM Fixed Price Basis Swaps– NYMEX (Henry Hub)

	December 31,			
	Volume		Average Price	
2020	96,200		$	2.85

Operating Cash Flows

We had net cash flows provided by operating activities for the nine months ended September 30, 2020 of approximately $24.4 million, compared to net cash flows provided by operating activities of approximately $44.3 million for the same period in 2019. This decrease was the result of lower throughput, termination of the Seco Pipeline Transportation Agreement, reduced commodity prices and production between the periods resulting in a decrease of approximately $21.5 million.

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

Investing Activities

We had net cash flows used in investing activities for the nine months ended September 30, 2020 of approximately $0.2 million compared to net cash flows used in investing activities of approximately $1.3 million for the same period in 2019, substantially all of which were related to midstream activities for both periods.

Financing Activities

Net cash flows used in financing activities was approximately $27.2 million for the nine months ended September 30, 2020. During the nine months ended September 30, 2020, we repaid borrowings of $34.0 million under our Credit Agreement and withdrew $7.0 million under the Revolving Loan.

Net cash flows used in financing activities was approximately $41.3 million for the nine months ended September 30, 2019. During this time, we distributed $17.7 million and $5.2 million to Class B Preferred Unitholders and common unitholders, respectively. Additionally, we repaid borrowings of $18.0 million under our Credit Agreement.

Off-Balance Sheet Arrangements

As of September 30, 2020, we had no off-balance sheet arrangements with third parties, and we maintain 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, Mesquite, the sale of oil and natural gas and our use of derivatives.

On August 11, 2019, the SN Debtors filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy code in the Bankruptcy Court, jointly administered under Case No. 19-34508 (the “SN Chapter 11 Case”). On January 13, 2020, we received written notice of termination from Mesquite terminating the Seco Pipeline Transportation Agreement, effective February 12, 2020. On June 30, 2020, the SN Debtors emerged from the SN Chapter 11 Case, with Sanchez Energy Company becoming a privately held corporation named Mesquite Energy, Inc. Given our midstream focus, our primary credit exposure relates to the creditworthiness of the counterparties under our gathering and processing agreements including, among other counterparties, Mesquite.

On June 6, 2020 the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, which will become effective only upon satisfaction of certain closing conditions described in the Settlement Agreement unless terminated earlier.

On June 23, 2020, certain affiliates of each Occidental Petroleum Corp., The Blackstone Group and GSO Capital Partners each filed a complaint (collectively, the "Rejection Lawsuits") against Mesquite and certain of its subsidiaries requesting, among other things, that the Bankruptcy Court not approve the rejection of certain commercial agreements, as set forth in the Settlement Agreement, in connection with Mesquite's Comanche Asset. The commercial agreements contemplated by the Settlement Agreement that the Partnership and its subsidiaries entered into on June 30, 2020 will not become effective until, among other things, the Rejection Lawsuits have been resolved in favor of the SN Debtors and the Bankruptcy Court has approved the rejection of the certain commercial agreements underlying the Rejection Lawsuits. The Rejection Lawsuits were not resolved by October 1, 2020, and as a result the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms. To date, none of the parties of the Settlement Agreement have provided notice of termination.

Any development that materially and adversely affects Mesquite's operations or financial condition, including the failure to favorably resolve the Rejections Lawsuits or termination of the Settlement Agreement, could have a material adverse impact on us, including but not limited to impairment losses on fixed assets. For additional information on the risks associated with our relationships with Mesquite, please read "Part I, Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2019, which was filed with the SEC on March 13, 2020 ("2019 10-K").

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 GAAP. 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 September 30, 2020, there were no changes with regard to the critical accounting policies disclosed in our 2019 10K. 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 our 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 Securities Exchange Act of 1934, as amended (the "Exchange Act") and are not required to provide the information required by 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 Exchange Act as of September 30, 2020 (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 September 30, 2020 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.

To date, no claims relating to the SN Chapter 11 Case have been filed against us. However, on March 13, 2020, the official committee of unsecured creditors in the SN Chapter 11 Case (the "Committee") filed the *Motion of the Official Committee of Unsecured Creditors for Leave, Standing, and Authority to Prosecute Claims on Behalf of the Debtors' Estate and for Related Relief* (the "Standing Motion"). In its Standing Motion, the Committee sought, in relevant part, authority from the Court to prosecute certain identified claims against the Partnership, the general partner and Catarina Midstream, LLC (collectively, the "SNMP Parties" and the claims, the "Claims") that, if valid, belong to Mesquite.

On June 30, 2020, the SN Debtors emerged from the SN Chapter 11 Case, with Sanchez Energy Corporation becoming a privately held corporation named Mesquite Energy, Inc. Upon emergence, the Claims re-vested, and are owned by, the Reorganized Debtors (as defined in the Plan). Accordingly, the Committee was dissolved and no longer retains the authority to bring all or a portion of the Claims against the SNMP Parties. Further, the Settlement Agreement contemplates, in relevant part, the settlement of the Claims between the Reorganized Debtors and the SNMP Parties. However, the Rejection Lawsuits were not resolved as of October 1, 2020, and as a result the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms. To date, none of the parties to the Settlement Agreement have provided notice of termination. The settlement of the Claims in accordance with the terms of the Settlement Agreement may be adversely impacted if the Bankruptcy Court does not rule in favor of the SN Debtors in the Rejection Lawsuits.

Item 1A. Risk Factors

Carefully consider the risk factors under the caption "Risk Factors" under Part I, Item 1A in our 2019 10K. There have been no significant changes except as follows:

The current COVID-19 pandemic could have a materially adverse impact on our business, including our financial condition, cash flows and results of operations. We are unable to predict the extent to which the pandemic and related impacts will adversely impact our business, including our financial condition, cash flows and results of operations.

Due to the COVID-19 pandemic and the current extraordinary and volatile market conditions, our business and operating results could be negatively impacted due to demand destruction as a result of the worldwide economic slowdown and governmental responses, including travel restrictions and stay-at-home orders. These conditions could also have a negative impact on our liquidity due to changes in the demand for our services, including a reduction in third-party or subsidiary revenue or the inability of our customers to honor their obligations under our commercial agreements. The full impact of the COVID-19 pandemic on the economy and our business is unknown and continuously evolving. The ultimate impact on our business will depend on numerous factors, including the duration of the effects of the pandemic on the economy, governmental responses to the COVID-19 pandemic, the demand for our services, and any deterioration in the creditworthiness of our customers.

The impacts the COVID-19 pandemic could have on our business include:

- a reduction in the availability or productivity of employees provided by SOG under the Services Agreement;
- a delay in timing for the collections of our receivables for the services we perform;
- an impairment of our intangible asset, equity investment or long-lived assets;
- a decrease in our ability to grow our business through organic projects or third-party acquisitions;
- our inability to meet the covenant requirements of the Credit Agreement;
- an impact on our liquidity position, which could result in our inability to pay our payables timely, including required payments under the Credit Agreement; and
- other factors discussed elsewhere in this Form 10-Q.

The foregoing and other continued disruptions to our business as a result of the COVID-19 pandemic could result in a material adverse effect on our business, result of operations, financial condition and cash flows. The COVID-19 pandemic may also have the effect of heightening some of the other risks described in the ‘‘Risk Factors’’ section of our 2019 10K.

We are currently not in compliance with the NYSE American listing standards. If our common units are delisted, it could result in even further reductions in the trading price and liquidity of our common units, which could materially adversely affect our ability to raise capital or pursue strategic transactions on acceptable terms, or at all.

Our common units are currently listed on the NYSE American. Continued listing of a security on the NYSE American is conditioned upon compliance with various continued listing standards. On April 3, 2020, we received the notice (the “Notice”) from the NYSE American stating that we were below compliance with the continued listing standards as set forth in Part 10 of the NYSE American Company Guide (the “Company Guide”). The Notice provided that the NYSE American’s review of the Partnership showed that we were below compliance with Section 1003(a)(i) of the Company Guide.

The Notice had no immediate effect on our listing on the NYSE American and, therefore, our common units will continue to be listed on the NYSE American, subject to our compliance with other continued listing requirements of the NYSE American. On May 4, 2020, we submitted a plan of compliance (the “Plan”) to the NYSE American addressing how we intend to regain compliance with Section 1003(a)(i) of the Company Guide by October 3, 2021. On June 25, 2020 the Partnership received a letter from the NYSE American stating that the Partnership’s Plan has been accepted and that the Partnership had been granted a plan period through October 3,2021 (the period of time from May 4, 2020 to October 3, 2021 (the “Plan Period”).

By October 3, 2021, we must either be in compliance with Section 1003(a)(i) of the Company Guide or must have made progress that is consistent with the Plan during the Plan Period. In addition, during the Plan Period, we must provide quarterly updates to the NYSE American concurrent with our interim and annual SEC filings. Failure to meet the requirements to regain compliance could result in the initiation of delisting proceedings.

The Notice does not affect our business operations or our reporting obligations under the rules and regulations of the SEC, nor does the Notice conflict with or cause an event of default under any of the Company’s material agreements.

If we cannot meet the NYSE American continued listing requirements by the end of the Plan Period, or if the NYSE American is not otherwise satisfied with our progress as of the end of the Plan Period, the NYSE American may delist our common units resulting in our common units trading in the less liquid over-the-counter market, which could have an adverse effect on us and the liquidity and market price of our common units. The delisting of our common units from the NYSE American could result in even further reductions in the trading price of our common units, substantially limit the liquidity of our common units, and materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NYSE American could also have other negative results, including the potential loss of confidence by vendors and employees, the loss of institutional investor interest and fewer business development opportunities. Our management is considering alternatives to ensure continued compliance with the NYSE American listing standards, but there is no assurance that we will continue to maintain compliance with the NYSE American continued listing standards.

Any termination of the Services Agreement requiring the payment of a termination fee may result in substantial dilution and could adversely affect our financial condition, results of operations, operating cash flows and any ability to pay cash distributions.

As disclosed in the October 13D described in more detail in “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Stonepeak Transaction,” Manager began engaging in non-binding discussions with the Board about terminating or, alternatively, amending and restating the Services Agreement. If the Services Agreement is terminated, and such termination ultimately requires the payment of a termination fee in cash, it could adversely affect our financial condition, results of operations, operating cash flows and any ability to pay cash distributions. If the Services Agreement is terminated and such termination ultimately requires the payment of a termination fee in common units, then holders of our common units will experience substantial dilution.

Certain events may result in our general partner exercising its limited call right, which may require common unitholders to sell their common units at an undesirable time or price.

Stonepeak owns and controls Manager. As a result, Manager and its affiliates may have the ability to cause our general partner to exercise its right to purchase all of the common units outstanding not held by our general partner or its controlled affiliates pursuant to Section 15.1 of the Amended Partnership Agreement. The Letter Agreement Transactions may lead to the ability of Stonepeak to be in the position to cause our general partner to exercise its limited call right. Additionally, such ability may also arise if the Services

Agreement is terminated and such termination requires the payment of a termination fee in common units. As described under the caption "Item 1A. Risk Factors—Risks Inherent in an Investment in Our Common Units—Our general partner has a limited call right that may require common unitholders to sell their common units at an undesirable time or price" in our 2019 10-K, if at any time our general partner and its controlled affiliates hold more than 80% of any class of outstanding limited partner interests, then our general partner will have the right, which it may assign or transfer in whole or in part to any of its controlled affiliates or to the Partnership, but not the obligation to acquire all, but not less than all, of such class of limited partner interests held by persons other than our general partner and its controlled affiliates at a price equal to the greater of (1) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the limited call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its controlled affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Common unitholders may also incur tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of common units to be repurchased upon exercise of the limited call right. Furthermore, there is no restriction in the Amended Partnership Agreement that prevents our general partner from causing us to issue additional common units, including in connection with the termination or renegotiation of the Services Agreement, and then exercising its limited call right. If our general partner exercises its limited call right, the effect would be to take the Partnership private and, if the common units are subsequently deregistered, the Partnership will no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended.

The failure of the Bankruptcy Court to approve the rejection of the certain commercial agreements underlying the Rejection Lawsuits, or termination of the Settlement Agreement, could adversely affect our business, financial condition, results of operations, operating cash flows and any ability to pay cash distributions.

On June 6, 2020, the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, including but not limited to, (i) Amendment No. 2, (ii) the Seco Catarina Agreement, and (iii) the Seco Comanche Agreement. Each of the agreements that were entered into on June 30, 2020 pursuant to the Settlement Agreement will become effective upon satisfaction of certain closing conditions described in the Settlement Agreement.

On June 23, 2020, certain affiliates of each Occidental Petroleum Corp., The Blackstone Group and GSO Capital Partners each filed the Rejection Lawsuits. The commercial agreements contemplated by the Settlement Agreement that the Partnership and its subsidiaries entered into on June 30, 2020 will not become effective until, among other things, the Rejection Lawsuits have been resolved and the Bankruptcy Court has approved the rejection of the certain commercial agreements underlying the Rejection Lawsuits in favor of the SN Debtors. The Rejection Lawsuits were not resolved as of October 1, 2020, and as a result, each of the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms.

The failure of the Bankruptcy Court to approve the rejection of the certain commercial agreements underlying the Rejection Lawsuits, or the termination of the Settlement Agreement could adversely affect our business, financial condition, results of operations, operating cash flows and any ability to pay cash distributions.

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

No common units were purchased during the nine months ended September 30, 2020.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

On November 16, 2020, the Partnership and Stonepeak entered into a letter agreement (the "Stonepeak Letter Agreement") wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The Stonepeak Letter Agreement also provides that Stonepeak will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the

end of such quarter. The Stonepeak Letter Agreement and the transactions contemplated therein, including the distribution for the three months ended September 30, 2020 (the "Letter Agreement Transactions"), was referred to the Conflicts Committee of the Board. The Conflicts Committee approved the Letter Agreement Transactions, recommended that the Board approve and authorize the execution and performance of the Letter Agreement Transactions, and verified that their approvals constituted "Special Approval" of the Letter Agreement Transactions under and pursuant to the Amended Partnership Agreement. Following the approval and recommendation from the Conflicts Committee, the Board approved the Letter Agreement Transactions. The aggregate distribution of 22,274,869 common units (the "Stonepeak Common Distribution Units") is payable to Stonepeak following the satisfaction of certain issuance conditions, including, among other things, the delivery by the Partnership of a fully executed supplemental listing application from the NYSE American approving the issuance of the Stonepeak Common Distribution Units and the compliance by the Partnership and Stonepeak with any applicable federal securities laws applicable to the issuance of the Stonepeak Common Distribution Units.

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
3.1	Amendment No. 4 to Limited Liability Company Agreement of Sanchez Midstream Partners GP LLC, dated September 7, 2020 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on September 9, 2020, File No. 001-33147).
3.2**	Letter Agreement, dated November 16, 2020, by and between Sanchez Midstream Partners LP, Sanchez Midstream Partners GP LLC and Stonepeak Catarina Holdings LLC.
10.1	Geophysical Seismic Data Use License Agreement, dated as of September 7, 2020, by and among Sanchez Oil & Gas Corporation, Sanchez Midstream Partners LP, Sanchez Midstream Partners GP LLC and SEP Holdings IV, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on September 9, 2020, File No. 001-33147).
10.2	Tenth Amendment to Third Amended and Restated Credit Agreement dated as of November 6, 2020, between Sanchez Midstream Partners LP, the lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on November 9, 2020, File No. 001-33147).
31.1**	Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2**	Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1***	Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2***	Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	Inline XBRL Instance Document
101.SCH**	Inline XBRL Schema Document
101.CAL**	Inline XBRL Calculation Linkbase Document
101.LAB**	Inline XBRL Label Linkbase Document
101.PRE**	Inline XBRL Presentation Linkbase Document
101.DEF**	Inline XBRL Definition Linkbase Document

** Filed herewith.

*** Furnished herewith.

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: November 16, 2020	By	/s/ Charles C. Ward
		Charles C. Ward
		Chief Financial Officer and Secretary
		(Duly Authorized Officer and Principal Financial Officer)

Exhibit 3.2

Sanchez Midstream Partners LP
1360 Post Oak Blvd, Suite 2400
Houston, TX 77056

November 16, 2020

Stonepeak Catarina Holdings LLC
55 Hudson Yards
550 W. 34th Street, 49th Floor
New York, NY 10001

Re: ***Class C Preferred PIK Units payable under that certain Third Amended and Restated Agreement of Limited Partnership, dated as of August 2, 2019 (the "Partnership Agreement") of Sanchez Midstream Partners LP (the "Partnership"). (Capitalized terms used but not defined herein have the respective meanings set forth therefor in the Partnership Agreement.)***

Mr. Howell & Mr. Taylor:

Subject to 5.9(d) of the Partnership Agreement, Section 13.1(d) of the Partnership Agreement provides that the General Partner, without the approval of any Partner, may amend any provision of the Partnership Agreement to reflect a change that the General Partner determines does not adversely affect the Limited Partners (including any particular class of Partnership Interests as compared to other classes of Partnership Interests) in any material respect. As you are aware, in light of the conflict of interest that may exist between the General Partner or its affiliates, including Stonepeak Catarina Holdings, LLC ("***Stonepeak***"), on the one hand, and the Partnership, any Group Member, any other Person who acquires an interest in a Partnership Interest or any person who is bound by the Partnership Agreement, on the other hand, in connection with this letter agreement and the transactions contemplated hereby, the board of directors of the General Partner (the "***Board***") has referred the negotiation of the matters related hereto to the Conflicts Committee.

The Conflicts Committee considered: (i) the issuance of the Subject Common Units (as defined below) to Stonepeak and all other transactions contemplated by this letter agreement (the "***Proposed Transaction***"); and (ii) the terms and conditions of this letter agreement.

The Conflicts Committee has: (i) determined in good faith that the Proposed Transaction is advisable and fair to and in the best interests of the Partnership and the unitholders other than SP Holdings, LLC, the General Partner or their respective affiliates, including Stonepeak; (ii) approved the Proposed Transaction for the purposes of providing "Special Approval" under Section 7.9 of the Partnership Agreement; and (iii) recommended to the Board that it approve the Proposed Transaction and this letter agreement and the related agreements and documentation required for the Proposed Transaction (this letter agreement and such related agreements and documentation, the "***Transaction Documents***").

The Board: (i) upon the recommendation of the Conflicts Committee, approved the Proposed Transaction and the Transaction Documents, (ii) determined that the Proposed Transaction and the Transaction Documents do not adversely affect the Limited Partners (including any particular class of Partnership Interests as compared to other classes of Partnership Interests) in any material respect, and (iii) authorized and empowered the officers of the General Partner to execute and deliver the Transaction Documents(collectively, the "***Board Approvals***").

Stonepeak, in its capacity as the Class C Preferred Holder, agrees that the Transaction Documents and the Proposed Transactions do not adversely affect it in its capacity as a Limited Partner in any material respect.

Pursuant to Section 5.9(b)(i) of the Partnership Agreement, the Partnership is required to pay the Class C Preferred Quarterly Distribution 100% in cash, except to the extent (a) Available Cash is insufficient to pay the Class C Preferred Quarterly Distribution or (b) such payments are prohibited by the Partnership's material financing documents. If the Class C Preferred Quarterly Distribution are not paid in cash due to an insufficiency of Available Cash or a prohibition in the Partnership's material financing documents, the Partnership must pay the Class C Preferred Quarterly Distribution in Class C Preferred PIK Units to the extent of such insufficiency or prohibition.

For the Quarter ended September 30, 2020 (the "***Third Quarter***"), the Partnership would be required to pay the Class C Preferred Quarterly Distribution in Class C Preferred PIK Units.

In accordance with our discussions, Stonepeak Catarina Holdings, LLC ("***Stonepeak***" and, together with the Partnership, the "***Parties***"), the sole beneficial owner of all outstanding Class C Preferred Units, has agreed to accept the Class C Preferred Quarterly Distribution for the Third Quarter in the form of 22,274,869 Common Units to be issued (all such Common Units being the "***Third Quarter Common Units***") promptly after the satisfaction of the Issuance Conditions (as defined below) with respect to such Third Quarter Common Units. For the avoidance of doubt, the number of Common Units included in the Third Quarter Common Units was determined utilizing the calculation detailed in paragraph (B) below based on a Common PIK Price of $0.57772, which is 110% the Closing Price on the last Trading Day prior to the execution of this letter agreement. Following the Partnership's having issued to Stonepeak all of the Third Quarter Common Units, the Partnership shall be deemed to have satisfied in full its obligation to make the Class C Preferred Quarterly Distribution under the Partnership Agreement with respect to the Third Quarter.

The respective obligations of the Parties are subject to the satisfaction of each of the following conditions (the "***Issuance Conditions***"):

(1) The Partnership has delivered to Stonepeak a fully executed "Supplemental Listing Application" approving the Subject Common Units for listing by the NYSE American, upon official notice of issuance of such Subject Common Units. The issuance of the Subject Common Units shall not contravene NYSE American rules and regulations.

(2) There shall not be pending any suit, action or proceeding by or before any federal, state, local or foreign government or political subdivision thereof, or any agency or instrumentality of such government or political subdivision, or any self-regulated organization or other non-governmental regulatory authority or quasi-governmental authority, or any arbitrator, court or tribunal of competent jurisdiction challenging or seeking to restrain, preclude, enjoin or prohibit the transactions contemplated by this letter agreement.

(3) Each Party has complied with applicable federal securities laws applicable to the issuance of the Subject Common Units, including the Securities and Exchange Act of 1934, as amended, and the rules and regulations promulgated thereunder.

In consideration of Stonepeak's acceptance of the Third Quarter Common Units in lieu of a distribution Class C Preferred PIK Units pursuant to this letter agreement, the Partnership agrees that notwithstanding Section 5.9(b)(i) of the Partnership Agreement, Stonepeak shall in all cases have the option to elect to receive the Class C Preferred Quarterly Distribution in Common Units (Common Units issued in lieu of Class C Preferred PIK Units for any Quarter are referred to as "***Subject Common Units***") for any Quarter following the Third Quarter, by providing written notice to the Partnership no later than the last day of the calendar month following the end of such Quarter ("***Written Notice***"). The Board Approvals included approval of certain amendments to the Partnership Agreement necessary to effectuate the Proposed Transaction. For any Quarter in which Stonepeak elects to receive Subject Common Units, the Partnership shall issue the applicable number of Subject Common Units on the distribution payment date to be established by the Board of Directors for such Quarter, subject to the

satisfaction of the Issuance Conditions. Following the Partnership's having issued to Stonepeak such Subject Common Units, the Partnership shall be deemed to have satisfied in full its obligations to make the Class C Preferred Quarterly Distribution for such Quarter.

This letter agreement shall be deemed an amendment to the Partnership Agreement and shall be conclusive and binding on any Limited Partner, any Person who acquires an interest in a Partnership Interest and any other Person who is bound by the Partnership Agreement. Furthermore, the Parties acknowledge and agree that the next time the Partnership Agreement is formally amended it will include formal amendments to give effect to this letter agreement.

The Parties acknowledge and agree that:

(A) Section 6.1(d)(xv)(A) of the Partnership Agreement shall apply, *mutatis mutandis*, to any issuance by the Partnership of Subject Common Units; and

(B) The number of Subject Common Units to be issued for any Quarter following the Third Quarter shall be calculated by (a) dividing the Class C Preferred Distribution Rate for such Quarter by the Common PIK Price for such Quarter and then (b) multiplying the result from clause (a) by the number of Class C Preferred Units held by Stonepeak. Any fractional Subject Common Unit will be rounded up to the nearest whole Subject Common Unit. As used herein, "***Common PIK Price***" means, for any Quarter after the Third Quarter, the greater of: (1) $0.5252 (subject to adjustment for unit splits, unit combinations, unit dividends and other similar events) and (2) an amount equal to (x), if the 2019 Warrant has not been exercised in full, the product of 110% multiplied by the Closing Price on the last Trading Day immediately prior to the date of the Written Notice for such Quarter, or (y), if the 2019 Warrant has been exercised in full, the Closing Price on the last Trading Day immediately prior to the date of the Written Notice for such Quarter.

[*Signature Pages Follow*]

If the foregoing accurately reflects our agreement with respect to the matters set forth in this letter agreement, please so acknowledge by signing below and returning a copy thereof to the undersigned.

Sincerely,

Sanchez Midstream Partners LP

By: Sanchez Midstream Partners GP LLC,
its general partner

By: /s/ Charles C. Ward
Name: Charles C. Ward
Title: Chief Financial Officer, Secretary and Treasurer

Sanchez Midstream Partners GP LLC

By: /s/ Charles C. Ward
Name: Charles C. Ward
Title: Chief Financial Officer, Secretary and Treasurer

ACKNOWLEDGED AND AGREED:

Acknowledgment of this letter agreement by Stonepeak Catarina Holdings, LLC shall be deemed its approval for the purposes of Section 5.9(d) of the Partnership Agreement.

Stonepeak Catarina Holdings, LLC

By: Stonepeak Catarina Upper Holdings, LLC,
its managing member

By: Stonepeak Infrastructure Fund (Orion AIV) LP,
its managing member

By: Stonepeak Associates LLC,
its general partner

By: Stonepeak GP Holdings LP,
its sole member

By: Stonepeak GP Investors LLC,
its general partner

By: Stonepeak GP Investors Manager LLC,
its managing member

By: /s/ Jack Howell
Name: Jack Howell
Title: Senior Managing Director

By: /s/ Luke Taylor
Name: Luke Taylor
Title: Senior Managing Director

Exhibit 31.1

SANCHEZ MIDSTREAM PARTNERS LP
CERTIFICATION

I, Gerald 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: November 16, 2020

/s/ Gerald F. Willinger

Gerald 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: November 16, 2020

/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, Gerald 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 September 30, 2020 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/ Gerald F. Willinger

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

Date: November 16, 2020

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 September 30, 2020 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: November 16, 2020