UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)
☒
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2019
OR
☐
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 001-33147

Sanchez Midstream Partners LP
(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State of organization)**	**11-3742489** **(I.R.S. Employer Identification No.)**
1000 Main Street, Suite 3000 **Houston, Texas** **(Address of Principal Executive Offices)**	**77002** **(Zip Code)**

(713) 783-8000
(Registrant's Telephone Number, Including Area Code)

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T 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, 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. (Check one):

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☒ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☒

The aggregate market value of Sanchez Midstream Partners LP common units held by non-affiliates as of June 28, 2019 was approximately $24,442,184 based upon the NYSE American closing price as of such date.

Common units outstanding on March 13, 2020: 19,975,193 common units.

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COMMONLY USED DEFINED TERMS

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

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

All of these types of statements, other than statements of historical fact included in this Form 10-K, are forward-looking statements. These forward-looking statements may be found in Part II, Item 7. and other items within this Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

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

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

- the resolution of the pending Sanchez Energy Chapter 11 Case (as defined in "Part I, Item 1A. Risk Factors") and its impact on our business, results of operations and financial condition;
- our ability to successfully execute our business, acquisition and financing strategies;
- the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements;
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, customers and other counterparties;
- our ability to extend, replace or refinance our Credit Agreement (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 1A. Risk Factors” in this Form 10-K and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

Management cautions all readers that the forward-looking statements contained in this Form 10-K 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

Item 1.Business

Overview

We are a growth-oriented publicly-traded limited partnership formed in 2005 focused on the acquisition, development and ownership of midstream and other energy-related assets in North America. We have ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, all located in the Western Eagle Ford in South Texas. We also own production assets in Texas and Louisiana. We have entered into a shared services agreement (the "Services Agreement") with Manager, pursuant to which Manager provides 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. On June 2, 2017, we changed our name to Sanchez Midstream Partners LP from Sanchez Production Partners LP. Our common units are currently listed on the NYSE American under the symbol "SNMP."

Our Relationship with Sanchez Energy, Manager and SOG

We believe that our relationship with Sanchez Energy and associated acreage dedications, provide us with a long range strategic advantage. As of March 13, 2020, Sanchez Energy owned approximately 11.4% of our outstanding common units. Since March 2015, we have completed three midstream asset acquisitions and two working interest acquisitions from Sanchez Energy. Pursuant to a right-of-first-offer, Sanchez Energy has agreed to offer us the right to acquire any midstream assets that it desires to sell. However, Sanchez Energy is under no obligation to sell any assets to us or to accept any offer for its assets that we may choose to make.

Manager is the sole member of our general partner, and has an interest in us through its ownership of all of our incentive distribution rights. To perform the scope of work defined in the Services Agreement, Manager has entered into a shared services agreement with SOG, which also has a shared services agreement in place with Sanchez Energy. We believe that our relationships with Manager and SOG provide us with a cost-effective means of operating our assets. SOG, which was formed in 1972, has a senior management team that averages over 20 years of industry experience. SOG has drilled or participated in over 4,000 wells, directly and through joint ventures, and has successfully built and operated extensive midstream and gathering assets associated with its exploration and production assets. We leverage SOG's extensive expertise and experience to execute on our business strategy.

Business Strategy

Our primary business objective is to create long-term value by generating stable and predictable cash flows that allow us to make, maintain and grow our cash distributions per common unit over time through the safe and reliable operation of our assets. We plan to achieve this objective by executing the following business strategy:

- grow our business by acquiring fee-based midstream and other energy-related assets with minimal maintenance capital requirements and low overhead costs to increase unitholder value;
- support stable cash flows by aligning our asset base and operations with SOG's operational platform and Sanchez Energy's asset base;
- focus on stable, fixed-fee businesses;
- grow our business through increased throughput; and
- maintain financial flexibility and a strong capital structure.

Our business strategy is subject to risks, please read “Part I, Item 1A. Risk Factors.”

Business Segments

Our business activities are conducted under two operating segments for which we provide information in our consolidated financial statements for the years ended December 31, 2019 and 2018. These two segments are based on the nature of the operations that are undertaken by each segment and are our:

- midstream business, which includes Western Catarina Midstream, the Carnero JV and Seco Pipeline (each as defined below); and
- production business, which includes non-operated oil and natural gas interests located in the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana.

For information about our segments’ revenues, profits and losses and total assets, see Note 18 “Reporting Segments” of our Notes to Consolidated Financial Statements.

Midstream Business

Western Catarina Midstream

In October 2015, we acquired (the “Catarina Transaction”) a gathering system from Sanchez Energy (“Western Catarina Midstream”), which is located on the western portion of Sanchez Energy’s approximately 106,000 net acres in Dimmit, La Salle and Webb counties, Texas (such net acreage is collectively referred to herein as “Sanchez Energy’s Catarina Asset,” and the western portion of such net acreage is individually referred to herein as “Western Catarina”). Western Catarina Midstream consists of approximately 150 miles of gathering pipelines, four main gathering and processing facilities, including stabilizers, storage tanks, compressors and dehydration units, and other related assets in Western Catarina, which are located in Dimmit and Webb counties, Texas, and services upstream production from assets located in the Eagle Ford Shale in South Texas. The gathering lines range in diameter from 4 to 12 inches, with a capacity of 200 MMcf/d for natural gas, and 40 MBbl/d for crude oil and NGLs. There are four main gathering and processing facilities, which include eight stabilizers of 5,000 Bbls per day, approximately 25,000 Bbls of storage capacity, pressurized storage for NGLs, approximately 18,000 horsepower of compression and approximately 300 MMcf/d of dehydration capacity. The gathering system is currently used solely to support the gathering, processing and transportation of natural gas, NGLs and crude oil produced by Sanchez Energy at Sanchez Energy’s Catarina Asset. The gathering system has oil interconnects with the Plains All American Pipeline, L.P. header system delivered to the Gardendale terminal, and to all four takeaway pipelines to Corpus Christi, and natural gas interconnects with Southcross Energy Partners, L.P., Kinder Morgan Inc., Energy Transfer Partners, L.P. and Targa Resources Corp.

In conjunction with the Catarina Transaction, we entered into a 15-year firm gas gathering and processing agreement with Sanchez Energy, pursuant to which Sanchez Energy agreed to tender all of its crude oil, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres in Western Catarina for processing and transportation through Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the “Gathering Agreement”).

All of the revenues from Western Catarina Midstream are currently earned from Sanchez Energy. During the first five years of the term of the Gathering Agreement (or through 2020), Sanchez Energy is required to meet a minimum quarterly volume delivery commitment for oil and natural gas, subject to certain adjustments. In addition, Sanchez Energy is required to pay contractually agreed upon gathering and processing fees for oil and natural gas volumes tendered through Western Catarina Midstream. In June 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by Sanchez Energy based on water that was delivered to Western Catarina Midstream through March 31, 2018. Since March 31, 2018, we have agreed with Sanchez Energy to continue adding the incremental infrastructure fee on a month-to-month basis.

During the year ended December 31, 2019, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.1 MBbls/d of oil, 131.7 MMcf/d of natural gas and 5.5 MBbls/d of water. The average age of the Western Catarina Midstream assets is approximately nine years, and such assets have an average expected life of approximately 21 additional years.

Carnero JV

In May 2018, we executed a series of agreements with Targa Resources Corp. (NYSE: TRGP) (“Targa”) and other parties pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering, LLC (“Carnero Gathering”) and Carnero Processing, LLC (“Carnero Processing”) (the “Carnero JV Transaction”) to form an expanded 50 / 50 joint venture in South Texas, Carnero G&P, LLC (“Carnero JV”), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant located in Bee County, Texas (“Silver Oak II”), to Carnero JV, which expanded the processing capacity of the joint venture 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 Carnero JV resulting in the joint venture owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) the Carnero JV received a new dedication from Sanchez Energy and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Sanchez Energy’s acreage in Dimmit, Webb, La Salle, Zavala and Maverick counties, Texas (such acreage is collectively referred to herein as “Sanchez Energy’s Comanche Asset”) pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche non-operated working interest owners, 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 joint ventures limited by the capacity of the 260 MMcf/d cryogenic natural gas processing plant in La Salle County, Texas (the “Raptor Gas Processing Facility.”)

Seco Pipeline

In August 2017, we completed construction of 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 Seco Pipeline provides upstream producers with optionality to southern gas markets and creates the potential to export natural gas to premium priced markets in Mexico. On September 1, 2017, we entered into a firm transportation service agreement with Sanchez Energy to transport certain quantities of Sanchez Energy’s natural gas on a firm basis through the Seco Pipeline for $0.22 per MMBtu delivered on or after September 1, 2017 (the “Seco Pipeline Transportation Agreement”). The Seco Pipeline Transportation Agreement had an initial term of one month and renewed automatically on a month-to-month basis. On January 13, 2020, we received written notice of termination from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective February 12, 2020. During the year ended December 31, 2019, Sanchez Energy transported average daily production through Seco Pipeline of approximately 1.9 MMcf/d of natural gas. The Seco Pipeline has an expected life of approximately 40 years.

Title to Properties

Title to Western Catarina Midstream and the Seco Pipeline assets are either owned in fee or derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license that is held by us or to the title to any material lease, easement, right-of-way, permit or lease we own, and we believe that we have satisfactory title to all of the material leases, easements, rights-of-way, permits and licenses with respect to all Western Catarina Midstream and Seco Pipeline assets.

Production Business

Our total estimated proved reserves at December 31, 2019, were approximately 3.0 MMBoe, all of which were classified as proved developed, with 11% being natural gas, 14% being NGLs, and 75% being oil. At December 31, 2019, we owned approximately 44 net producing wells. Our total average proved reserve-to-production ratio is approximately 10 years and our portfolio decline rate is 12% based on our estimated proved reserves at December 31, 2019.

Below is a description of our operations and our oil and natural gas properties by basin at December 31, 2019:

Locations

Of our reserves, 99% were located in the Eagle Ford Shale on non-operated properties. Production during the year ended December 31, 2019 on these properties was 306.1 MBoe and approximately 2,955.2 MBoe of estimated proved reserves were held at December 31, 2019. All of these reserves were classified as proved developed, with 11% being natural gas, 14% being NGLs, and 75% being oil.

The remaining reserves were located on non-operated properties in Louisiana. During the year ended December 31, 2019, production on Louisiana properties was 2.9 MBoe, and approximately 44.1 MBoe of estimated proved reserves were held at December 31, 2019, all of which were classified as proved developed with 100% being oil.

Operations

We do not currently operate any of our production assets. The Eagle Ford Shale properties are operated by either SOG, Sanchez Energy or Marathon Oil Company and the Louisiana properties are operated by SOG.

Proved Reserves of Natural Gas, NGLs, and Oil

The following table reflects our estimates for proved natural gas, NGLs and oil reserves based on the SEC definitions that were used to prepare our financial statements for the periods presented. The standardized measure values shown in the table are not intended to represent the current market values of our estimated proved reserves.

Reserve data:	**2019**	**2018**
Estimated proved reserves:		
Oil (MMBbl)	2.2	2.5
Natural gas (MMcf)	2.1	2.7
NGLs (MMBbl)	0.4	0.5
Total proved reserves (MMBoe)	3.0	3.5
Estimated proved developed reserves:		
Oil (MMBbl)	2.2	2.5
Natural gas (MMcf)	2.1	2.7
NGLs (MMBbl)	0.4	0.5
Total proved developed reserves (MMBoe)	3.0	3.5
Proved developed reserves as a percent of total reserves	100%	100%
Standardized measure ($ in millions)[a]	$ 38.4	$ 52.2

(a) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves. It is determined using SEC-required prices and costs in effect as of the time of estimation without giving effect to non-property related expenses (such as general and administrative expenses or debt service costs) and discounted using an annual discount rate of 10%. Our standardized measure does not include the impact of derivative transactions or future federal income taxes because we are not subject to federal income taxes. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure shown should not be considered the current market value of our reserves. The 10% discount factor used to calculate present value, which is required, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. Please read "Part I, item 1A. Risk Factors."

Our 2019 estimates of total proved reserves decreased 0.5 MMBoe from 2018 due to production and revisions of previous estimates of 0.3 MMBoe and 0.2 MMBoe, respectively.

As of December 31, 2019, we had no remaining proved undeveloped reserves in our reserves base.

We expect to make minimal capital expenditures related to recompletion of existing wells during the year ending December 31, 2020.

At December 31, 2019 and December 31, 2018, Ryder Scott Co. LP ("Ryder Scott"), an independent oil and natural gas engineering firm, prepared estimates of all our proved reserves. We used these estimates of our proved reserves to prepare our financial statements. Ryder Scott maintains a degreed staff of highly competent technical personnel. The average experience level of Ryder Scott's technical staff of engineers, geoscientists and petrophysicists exceeds 20 years, including five to 15 years with a major oil company. The engineering information presented in their report was overseen by Mr. Eric Nelson, P.E. Mr. Nelson is an experienced reservoir engineer having been a practicing petroleum engineer since 2002. He has more than 13 years of experience in reserves evaluation with Ryder Scott. He has a Bachelor of Science degree in Chemical Engineering from the University of Tulsa and Master of Business Administration degree from the University of Texas. Mr. Nelson is a Registered Professional Engineer in the State of Texas. Our activities with Ryder Scott are coordinated by a reservoir engineer employed by us who has approximately 38 years of experience in the oil and natural gas industry and an engineering degree from the University of Tennessee and a Master of Business Administration from the University of New Orleans. He is a member of the Society of Petroleum Engineers. He has prior reservoir engineering and reserves management experience at Exxon Mobil Corporation, Dominion Resources and Hilcorp Energy. He has extensive experience in managing oil and natural gas reserves processes. He serves as the key technical person reviewing the reserve reports prepared by Ryder Scott prior to review by the Audit Committee and approval by the Board.

Production and Price History

The following table sets forth information regarding net production of natural gas, NGLs and oil and certain price and cost information for each of the periods indicated:

	Years Ended December 31, 2019	Years Ended December 31, 2018	Variance	
Net production:				
Natural gas (MMcf)	231	434	(203)	(47%)
Oil production (MBbl)	228	296	(68)	(23%)
NGLs (MBbl)	42	71	(29)	(41%)
Total production (MBoe)	309	439	(130)	(30%)
Average daily production (Boe/d)	847	1,203	(356)	(30%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 2.24	$ 2.30	$ (0.06)	(3%)
Natural gas price per Mcf without hedge settlements	$ 1.84	$ 2.39	$ (0.55)	(23%)
Oil price per Bbl with hedge settlements	$ 62.94	$ 62.64	$ 0.30	0%
Oil price per Bbl without hedge settlements	$ 59.40	$ 67.14	$ (7.74)	(12%)
NGL price per Bbl without hedge settlements	$ 12.83	$ 24.07	$ (11.24)	(47%)
Total price per Boe with hedge settlements	$ 49.86	$ 48.41	$ 1.45	3%
Total price per Boe without hedge settlements	$ 46.94	$ 51.52	$ (4.58)	(9%)
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 21.04	$ 17.82	$ 3.22	18%
Lease operating expenses	$ 19.03	$ 15.31	$ 3.72	24%
Production taxes	$ 2.01	$ 2.51	$ (0.50)	(20%)
Depreciation, depletion and amortization	$ 12.76	$ 10.93	$ 1.83	17%

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

Existing Wells

The following table sets forth information at December 31, 2019, relating to the existing wells in which we owned a working interest as of that date. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas Gross	Natural Gas Net	Oil Gross	Oil Net
Operated	—	—	—	—
Non-operated	—	—	91	44
Total	—	—	91	44

We did not convert any proved undeveloped wells into proved producing wells in 2019.

Drilling Activity

With respect to oil and natural gas wells drilled and completed during the years ended December 31, 2019 and 2018, the information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that are capable of producing commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled on any of our properties during the years ended December 31, 2019 or 2018. During the years ended December 31, 2019 and 2018, there were no wells drilled and there were no wells in progress.

Developed and Undeveloped Acreage

The following table sets forth information related to our leasehold acreage as of December 31, 2019.

	Developed Acreage[(a)]		**Undeveloped Acreage**[(b)]	
	Gross[(c)]	**Net**[(d)]	**Gross**[(c)]	**Net**[(d)]
Total	702	140	—	—

(a) Developed acres are acres pooled within or assigned to productive wells/units.
(b) Undeveloped acres are acres on which wells have not been drilled or acres that have not been pooled into a productive unit.
(c) A gross acre is an acre in which a working interest is either fully or partially leased. The number of gross acres may include minerals not under lease as a result of leasing some but not all joint mineral owners under any given tract.
(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Leases

Most of our reserves are comprised of wellbore rights only. We have a small lease position of less than 150 net acres in Louisiana.

Marketing and Major Customers

Our oil and natural gas production in Texas and Louisiana is marketed by the operators of our properties.

Sanchez Energy accounted for 86% and 71% of our total revenue for the years ended December 31, 2019 and 2018, respectively. We are highly dependent upon Sanchez Energy as our most significant customer, and we expect to derive a substantial portion of our revenue from Sanchez Energy in the foreseeable future. Accordingly, we are indirectly subject to the business risks of Sanchez Energy. Any development that materially and adversely affects Sanchez Energy's operations or financial condition could have a material adverse impact on us. Additional information regarding our relationship with Sanchez Energy is provided in "Part III, Item 13. Certain Relationships and Related Transactions, and Manager Independence." For additional information on the risks associated with our relationship with Sanchez Energy, please read "Part I, Item 1A. Risk Factors."

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil, NGLs and natural gas and retaining trained personnel. Many of our competitors have substantially greater financial, technical and personnel resources than us. As a result, our competitors may be able to outbid us for assets, more competitively price their gathering and transportation services and oil and natural gas production, or utilize superior technical resources than our financial or personnel resources permit. Our ability to acquire additional assets will depend on our ability to evaluate and select suitable assets and to consummate transactions in a competitive environment.

The natural gas gathering, compression, treating and transportation business is very competitive. Upon such time that we seek to obtain customers in addition to Sanchez Energy for Western Catarina Midstream, our competitors will include other midstream companies, producers and intrastate and interstate pipelines. Competition for volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies.

Neither SOG nor any of its related companies are restricted from competing with us. Additional information regarding our relationship with SOG is provided in “Part III, Item 13. Certain Relationships and Related Transactions, and Manager Independence.”

Governmental Regulation

Environmental Laws

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentrations of various substances, including water and waste, that can be released into the environment;
- limit or prohibit activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible in the absence of such regulations. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. In addition, federal, state and local authorities frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

Environmental laws and regulations that could have a material impact on the oil and natural gas industry and our operations include the following:

Waste Handling

The Resource Conservation and Recovery Act (“RCRA”) and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous wastes. With the approval of the federal Environmental Protection Agency (“EPA”), the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent requirements. Drilling fluid, produced water and most other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA’s non-hazardous waste provisions. Although we do not believe that the current costs of managing any of our wastes are material under presently applicable laws, any future reclassification of oil and natural gas exploration, development and production wastes as hazardous wastes, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the Superfund law, can impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons can include the owners or operators of the site where the release occurred, and anyone who disposed of, or arranged for the disposal of, a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, including response costs, alternative water supplies, damages to natural resources and the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Each state also has environmental cleanup laws analogous to CERCLA.

We currently own, lease or operate numerous properties that have been used for oil and natural gas production for a number of years. Although we believe that operating and waste disposal practices utilized in the past with respect to these properties were typical for the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, these properties have been operated by third parties or by previous owners or operators whose practices, including the treatment and disposal or release of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future environmental harm.

Water Discharges

The Federal Water Pollution Control Act (the “Clean Water Act”), and comparable state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, impose investigatory or remedial obligations and issue injunctions limiting or preventing our operations for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Oil Pollution Act

The Oil Pollution Act of 1990 amended the Clean Water Act in large part due to the Exxon Valdez incident. Under the Oil Pollution Act, the EPA was directed to promulgate regulations which would create a comprehensive prevention, response, liability and compensation program to deal with oil discharged into United States navigable waters. The Oil Pollution Act imposes ongoing requirements on owners and operators of facilities that handle certain quantities of crude oil, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with a spill. The Oil Pollution Act imposes liability for removal costs and damages resulting from an incident in which oil is discharged into navigable waters and establishes liability for damages for injuries to, or loss of, natural resources.

Air Emissions

The Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. In October 2015, the EPA finalized rules that lower the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 parts per billion (“ppb”) to 70 ppb, and the EPA published a final rule in July 2018 completing the final designations. States can also impose air emissions limitations that are more stringent than the federal standards imposed by the EPA. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. Rules restricting air emissions may require a number of modifications to our operations, including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. However, we believe that our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies. We believe that our operations are in substantial compliance with federal and state air emission standards.

Climate Change

While the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, the EPA has used existing Clean Air Act authority to regulate GHGs. For example, the EPA has adopted rules requiring the reporting of GHG emissions from various oil and natural gas operations on an annual basis. In addition, in June 2016, the EPA published New Source Performance Standards (“NSPS”) Subpart

OOOOa standards that require new, modified or reconstructed facilities in the oil and natural gas sector to reduce methane gas and volatile organic compound emissions. However, in June 2017, the EPA published a proposed rule to stay portions of the Subpart OOOOa standards for two years. In September 2018, the EPA issued proposed revisions to the NSPS applicable to new and modified oil and gas sources, which would reduce the monitoring obligations for wells and compressor stations. Further in October 2018, the EPA issued a draft report which includes a template designed to assist with compliance. Until the rules are finalized, the implementation of the 2016 rules remains uncertain. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to possess and acquire emission allowances which permit corresponding GHG emissions. Furthermore, the U.S. is currently a party to the Paris Agreement adopted in December 2015 to reduce global GHG emissions. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement in accordance with the Agreement's four-year exit process and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement and in November 2019 began the formal process of withdrawl.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices and has finalized a study of the potential environmental impacts of hydraulic fracturing activities, finding that under certain circumstances, the "water cycle" activities associated with hydraulic fracturing may impact drinking water resources. In 2014, the EPA released an Advanced Notice of Proposed Rulemaking seeking public comment on its plans to issue regulations under the Toxic Substances Control Act of 1976 to require companies to disclose information regarding chemicals used in hydraulic fracturing. Further, the Department of the Interior has released final regulations governing hydraulic fracturing on federal oil and natural gas leases which require lessees to file for approval of well stimulation work before commencement of operations and require well operators to disclose the trade names and purposes of additives used in the fracturing fluids. The states in which we operate have also adopted disclosure requirements related to fracturing fluids. Legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Currently, no states in which we utilize hydraulic fracturing have adopted these regulations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing hydraulic fracturing would impact our business.

Endangered Species

The federal Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions and may materially delay or prohibit land access for development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS was required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities.

Gathering System Regulation

Regulation of gathering facilities may affect certain aspects of our business and the market for our services. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the Federal Energy Regulatory Commission ("FERC"). The FERC regulates interstate natural gas transportation rates, terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

The transportation and sale for resale of natural gas in interstate commerce are regulated primarily under the Natural Gas Act ("NGA"), and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation, gathering, and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the U.S. Congress and by FERC regulations.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests that the FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations. In addition, the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our natural gas gathering facilities are subject to change based on future determinations by the FERC, the courts, or the U.S. Congress. If the FERC were to determine that an individual gathering system is not exempt from FERC regulation and the pipelines associated with such gathering system provide interstate transportation, the rates for, and terms and conditions of, services provided by such gathering system would be subject to regulation by the FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect results of operations and cash flows. If any of our facilities were found to have provided services or otherwise operated in violation of the NGA or the NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

Gathering services, which may occur upstream of transmission service subject to FERC jurisdiction, is regulated by the states. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. Our purchasing and gathering operations are subject to ratable take and common purchaser statutes in the State of Texas. The ratable take statute generally requires gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, the common purchaser statute generally requires gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport gas.

The Railroad Commission of Texas ("TRRC") requires gatherers to file reports, obtain permits, make books and records available for audit and provide service on a nondiscriminatory basis. Shippers and producers may file complaints with the TRRC to resolve grievances relating to natural gas gathering access and rate discrimination.

While our gathering systems have not been regulated by the FERC under the NGA, the U.S. Congress may enact legislation or the FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further regulation. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas gatherers with which we compete. Failure to comply with those regulations in the future could subject us to civil penalty liability.

The Energy Policy Act of 2005 ("EPAct 2005"), amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by the FERC, and furthermore provides the FERC with additional civil penalty authority. The EPAct 2005 provided the FERC with the power to assess daily civil penalties for violations of the NGA and the Natural Gas Policy Act ("NGPA"). The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. In Order No. 670, the FERC promulgated rules implementing the anti-market manipulation provision of the EPAct 2005. The rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to: (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

Pipeline Safety Regulation

We are subject to regulation by the United States Department of Transportation ("DOT") through the Pipelines and Hazardous Materials Safety Administration ("PHMSA"), pursuant to the Hazardous Liquid Pipeline Safety Act of 1979, as amended ("HLPSA") and comparable state statutes with respect to design, installation, inspection, testing, construction, operation, replacement and maintenance of pipeline facilities. HLPSA, as amended, governs he design, installation, testing, construction, operation, replacement and management of crude oil pipeline facilities and also covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the U.S. Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

Our natural gas pipelines are subject to regulation by PHMSA pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA") and the Pipeline Safety Improvement Act of 2002 ("PSIA"), as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("PIPES Act"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas ("HCAs").

PHMSA has developed regulations that require pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact HCAs;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

The HLPSA has been amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2011 Pipeline Safety Act doubled the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1 million to $2 million for a related series of violations, but provided that these maximum penalty caps do not apply to certain civil enforcement actions. Effective April 27, 2017, to account for inflation, those maximum civil penalties were increased to $213,268 per day, with a maximum of $2,132,679 for a series of violations. The 2016 Pipeline Safety Act extended PHMSA's statutory mandate through 2019. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

PHMSA regularly revises its pipeline safety regulations and has published advanced notices of proposed rulemakings and notices of proposed rulemaking to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations. In the past few years, PHMSA issued advisory bulletins providing guidance on applicable regulatory requirements, including those that must be followed for the abandonment of a pipeline; aspects of overall pipeline integrity, including the need for corrosion-control systems on buried and insulated pipeline segments, to conduct in-line inspections for all threats, and to ensure in-line inspection tool findings are accurate and verified; the need of owners and operators of natural gas facilities to take appropriate steps to prevent damage to pipeline facilities from accumulated snow or ice; actions pipeline operators should consider taking to ensure the integrity of pipelines in the event of severe flooding or hurricane damage; notice of construction; flow reversal procedures; product changes and conversion; integrity management program evaluation metrics; and incident response plans. Further changes to PHMSA's rules are expected in the future.

For example, in July 2015, PHMSA issued a notice of proposed rulemaking proposing, among other things, to extend operator qualification requirements to operators of certain natural gas gathering lines and to add a specific timeframe for operators' notifications of accidents or incidents. In January 2017, PHMSA issued a final rule adding a specific timeframe for operators' notifications of accidents or incidents but delayed final action on the operator qualification proposals until a later date. The final rule became effective March 24, 2017. In addition, in October 2015, PHMSA issued a notice of proposed rulemaking proposing changes to its hazardous liquid pipeline safety regulations, including to extend: (i) reporting requirements to all onshore or offshore, regulated or unregulated hazardous liquid gathering lines; and (ii) certain integrity management periodic assessment and remediation requirements to regulated onshore gathering lines. On January 13, 2017, PHMSA issued a final rule amending its regulations to impose new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. The final rule also significantly extends and expands the reach of certain integrity management requirements, regardless of the pipeline's proximity to HCAs. However, this final rule remains subject to review and approval by the new administration, pursuant to a memorandum issued by the White House to heads of federal agencies. It is unclear whether the final rule will be revised and when it will be implemented. In April 2016, PHMSA issued a notice of proposed rulemaking that would expand integrity management requirements and impose new pressure requirements on currently regulated gas transmission pipelines and would also significantly expand the regulation of gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. On October 1, 2019, PHMSA issued its final rule which will become effective July 1, 2020. While we cannot predict the outcome of legislative or regulatory initiatives, such regulatory changes and any legislative changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations.

Furthermore, DOT regulations have incorporated by reference the American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of storage tanks. API 653 requires regularly scheduled inspection and repair of such tanks. These periodic tank maintenance requirements may result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our storage tanks.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing intrastate pipeline regulations and inspection of intrastate pipelines. For example, in Texas the Pipeline Safety Department of the TRRC inspects and enforces the pipeline safety regulations for intrastate pipelines, including gathering lines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include more stringent requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We have incorporated all existing requirements into our programs by the required regulatory deadlines and are continually incorporating the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and upcoming changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity gathered on our system, or a regulatory inspection identifies a deficiency in our required programs.

Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA"), and comparable state laws. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communications standard, OSHA Process Safety Management, the EPA community right-to-know regulations under Title III of CERCLA and similar state laws require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements should not have a material adverse impact on our financial condition and results of operations. As of December 31, 2019, we had no accrued environmental obligations. We are not aware of any environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore, cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or cash flows.

Employees

We do not have any employees. In connection with providing the services under the Services Agreement, Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties, (ii) reimbursement for all allocated overhead costs, as well as any direct third-party costs incurred and (iii) for each asset acquisition, disposition or financing, a fee not to exceed 2% of the value of such transaction.

As of March 13, 2020, nine (9) employees were employed by SOG with their primary function being to provide services for us, all of which were full-time employees.

None of SOG's employees are subject to a collective bargaining agreement.

Offices

Our principal executive offices are located at 1000 Main Street, Suite 3000, Houston, Texas 77002. Our telephone number is (713) 783-8000.

Available Information

Our internet address is http://www.sanchezmidstream.com. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC maintains an internet website that contains these reports at http://www.sec.gov.

Item 1A. Risk Factors

Our business involves a high degree of risk. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Form 10-K, including the financial statements and the related notes appearing at the end of this Form 10-K. If any of the following risks, or any risk described elsewhere in this Form 10-K, were to occur, our business, financial condition or results of operations could be adversely affected. If any of the following risks, or any risk described elsewhere in this Form 10-K, were to occur, our business, financial condition or results of operations could be adversely affected. The risks below are not the only ones facing the Partnership. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below. Also, please read "Cautionary Note Regarding Forward-Looking Statements."

The risk factors in this Form 10-K are grouped into the following categories:

- Risks Related to Our Midstream Business;
- Risks Related to Our Production Business;
- Risks Related to Our Midstream and Production Businesses;
- Risks Related to Financing and Credit Environment;
- Risks Related to Our Cash Distributions;
- Risks Related to Regulatory Compliance;
- Risks Inherent in an Investment and Our Common Units; and
- Tax Risks.

Risks Related to Our Midstream Business

Because the majority of our total revenue, including substantially all of our revenue stemming from the operation of our midstream business, is derived from Sanchez Energy, the filing of voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code by Sanchez Energy and certain of its subsidiaries could have a material and adverse impact on us.

Sanchez Energy accounted for approximately 86% of our total revenue and substantially all of our midstream business revenue for the year ended December 31, 2019. We are dependent on Sanchez Energy as our only current customer for utilization of Western Catarina Midstream, and as our primary customer for utilization of our other midstream assets. We expect that a majority of revenues relating to these assets will be derived from Sanchez Energy for the foreseeable future.

On August 11, 2019, Sanchez Energy Corporation and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division, jointly administered Case No. 19-34508 (the "Sanchez Energy Chapter 11 Case"). As a result, we are subject to an increased risk of non-payment, non-performance and/or underutilization of our midstream assets by Sanchez Energy. While Sanchez Energy Corporation has stated it intends to continue to operate in the normal course and intends to interact with its commercial counterparties as usual, no assurances can be given as to the timing or outcome of the bankruptcy process. Through December 31, 2019, we did not experience any significant losses as a result of non-performance. However, as disclosed herein, Sanchez Energy terminated the Seco Pipeline Transportation

Agreement effective on February 12, 2020. Any development that materially and adversely affects Sanchez Energy's operations or financial condition could have a material and adverse impact on us.

On March 13, 2020, the official committee of unsecured creditors in the Sanchez Energy Chapter 11 Case (the "Unsecured Committee") filed a motion titled *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 "March 13 Motion"). The relief sought in the March 13 Motion is to grant the Unsecured Committee derivative standing to prosecute claims that Sanchez Energy allegedly has against the Partnership and others, including, but not limited to, claims to recharacterize or avoid the Catarina Transaction, the Carnero Gathering Transaction (as defined in Note 12 "Investments" of our Notes to Consolidated Financial Statements), and the Carnero Processing Transaction (as defined in Note 12 "Investments" of our Notes to Consolidated Financial Statements). While we do not believe these claims have any merit, if such claims are filed and prosecuted, the cost to defend against such claims and any judgment entered against us could have a material and adverse impact on our business, financial condition and operating results.

Because of the natural decline in production from existing wells, our success depends, in part, on Sanchez Energy's ability to replace declining production. Any decrease in volumes of natural gas, NGLs and oil that Sanchez Energy produces or any decrease in the number of wells that Sanchez Energy completes could reduce throughput volumes that could adversely affect our business and operating results.

The volumes that support our facilities depend on the level of production from wells connected to our facilities, which may be less than expected and will naturally decline over time. To the extent Sanchez Energy reduces its activity or otherwise ceases to drill and complete wells, especially on Sanchez Energy's Catarina Asset, revenues for our gathering and processing services will be directly and adversely affected. In addition, volumes from completed wells will naturally decline and our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our facilities, we must obtain new sources of natural gas, NGLs and oil from Sanchez Energy or other third parties. The primary factors affecting our ability to obtain additional sources of natural gas, NGLs and oil include (i) the success of Sanchez Energy's drilling activity in our areas of operation, (ii) Sanchez Energy's acquisition of additional acreage and (iii) our ability to obtain additional dedications of acreage from Sanchez Energy or new dedications of acreage from other third parties.

We have no control over Sanchez Energy's or other producers' levels of development and completion activity in our areas of operation, the amount of reserves associated with wells connected to our facilities or the rate at which production from a well declines. We have no control over Sanchez Energy or other producers or their development plan decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected prices for natural gas, NGLs and oil;
- demand for natural gas, NGLs and oil;
- levels of reserves;
- geologic considerations;
- environmental or other governmental regulations, including the availability and maintenance of drilling permits and the regulation of hydraulic fracturing; and
- the costs of producing natural gas, NGLs and oil and the availability and costs of drilling rigs and other equipment.

Under the terms of the lease covering Sanchez Energy's Catarina Asset, Sanchez Energy is subject to annual drilling and development requirements. For example, at the present time, the lease requires Sanchez Energy to drill 50 wells per year (with the ability to bank up to 30 wells from a prior period). The pending Sanchez Energy Chapter 11 Case has resulted in significant delays to the drilling program on Sanchez Energy's properties, including Sanchez Energy's Catarina

Asset, and failure to drill the required number of wells could result in forfeiture of acreage not held by production during the current fiscal year. In addition, Sanchez has various drilling obligations under the leases covering Sanchez Energy's Comanche Asset. If Sanchez Energy fails to meet these drilling obligations, Sanchez Energy could forfeit its acreage under the applicable lease not held by production. Such a forfeiture could impact Sanchez Energy's ability to develop additional acreage and replace declining production.

Fluctuations in energy prices can also greatly affect the development of reserves. Declines in commodity prices could have a negative impact on Sanchez Energy's development and production activity, and if sustained, could lead Sanchez Energy to materially reduce its drilling and completion activities. Sustained reductions in development or production activity in our areas of operation could lead to reduced utilization of our services.

Due to these and other factors, even if reserves are known to exist in areas served by our facilities, Sanchez Energy and other producers may choose not to develop, or be prohibited from developing, those reserves. If reductions in development activity result in our inability to maintain the current levels of throughput on our facilities, those reductions could reduce our revenue and cash flows and adversely affect our ability to pay cash distributions to Stonepeak Catarina Holdings LLC ("Stonepeak Catarina"), as the holder of all of our Class C preferred units representing limited partner interests (the "Class C Preferred Units"). Restrictions under our Credit Agreement and our partnership agreement currently prohibit us from paying distributions to our common unitholders.

The Gathering Agreement contains provisions that can reduce the stability in cash flows that the agreement was designed to achieve.

The Gathering Agreement is designed to generate stable cash flows for us over the life of the minimum volume commitment contract term while also minimizing direct commodity price risk. Under the minimum volume commitment, subject to certain adjustments, Sanchez Energy has agreed to ship a minimum volume of natural gas and NGLs on Western Catarina Midstream or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the minimum volume commitment, which is the first five years of the 15-year term of the Gathering Agreement (or through 2020). In addition, the Gathering Agreement also includes a minimum quarterly quantity, which is a total amount of natural gas and NGLs that Sanchez Energy must flow on Western Catarina Midstream (or an equivalent monetary amount) each quarter during the minimum volume commitment term. If Sanchez Energy's actual throughput volumes are less than its minimum volume commitment for the applicable period, it must extend the minimum volume commitment term on a nominal volume basis, but to no longer than the original five years (subject to certain exceptions), or, in some cases, make a shortfall payment to us at the end of that contract quarter, as applicable. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped, processed or offset through an extension of the minimum volume commitment term for the applicable period and the minimum volume commitment for the applicable period, multiplied by the applicable fee. To the extent that Sanchez Energy's actual throughput volumes are above its minimum volume commitment for the applicable period, the Gathering Agreement contains provisions that allow Sanchez Energy to use the excess volumes as a credit to shorten the minimum volume commitment term, but to no less than four years. Through December 31, 2019, natural gas volumes from Sanchez Energy have shortened the primary terms of the volume commitments by 197 days, while the minimum oil volume commitment is no longer in effect.

Under certain circumstances, it is possible that the combined effect of the minimum volume commitment provisions could result in our receiving substantially reduced revenues or cash flows from Sanchez Energy in a given period. In the most extreme circumstances:

- we could incur operating expenses with substantially reduced corresponding revenues from Sanchez Energy; or
- Sanchez Energy could cease shipping throughput volumes at a time when its aggregate minimum volume commitment has been satisfied with previous throughput volume shipments.

If either of these circumstances were to occur, it would have a material adverse effect on our results of operations and financial condition and cash flows and our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Interruptions in operations at our facilities or facilities that Targa operates on behalf of the Carnero JV may adversely affect operations and cash flows available for distribution to Stonepeak Catarina.

Any significant interruption at any of our facilities or the facilities that Targa operates on behalf of the Carnero JV, or in our ability or Targa's ability on behalf of the Carnero JV, as applicable, to gather, treat or process natural gas, NGLs and oil, would adversely affect operations and cash available for distribution to Stonepeak Catarina as the holder of all of our Class C Preferred Units. Operations at impacted facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at physical plants or pipeline facilities;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption or decline in the supply of resources necessary to operate a facility;
- damage to facilities resulting from natural gas, NGLs and oil that do not comply with applicable specifications; and
- inadequate transportation or market access to support production volumes, including lack of availability of pipeline capacity.

We may not be able to attract additional third-party volumes, which could limit our ability to grow and would increase our dependence on Sanchez Energy.

Part of our long-term growth strategy includes identifying additional opportunities to offer gathering, processing and transportation services to other third parties. Our ability to increase throughput on our facilities and any related revenue from third parties is subject to numerous factors beyond our control, including competition from third parties and the extent to which we have available capacity when requested by third parties. To the extent that we lack available capacity on our facilities for third-party volumes, we may not be able to compete effectively with third-party gathering or processing systems for additional volumes. In addition, some of our competitors for third-party volumes have greater financial resources and access to larger supplies of oil and natural gas than those available to us, which could allow those competitors to price their services more aggressively than us. Moreover, the underlying lease for the properties on which Western Catarina Midstream is located restricts Western Catarina Midstream to the handling of hydrocarbons produced on the properties covered by the lease.

We may not be able to attract material third-party service opportunities. Our efforts to attract new unaffiliated customers may be adversely affected by (i) our relationship with Sanchez Energy, certain rights that it has under applicable agreements and with respect to Western Catarina Midstream the fact that a substantial portion of the capacity of the facility will be necessary to service Sanchez Energy's production and development and completion schedule, (ii) the current nature of our facilities, (iii) our desire to provide services pursuant to fee-based contracts and (iv) the existence of current and future dedications to other gatherers by potential third-party customers. As a result, we may not have the capacity or ability to provide services to third parties, or potential third-party customers may prefer to obtain services pursuant to other forms of contractual arrangements under which we would be required to assume direct commodity exposure.

All of our midstream assets are located in the Eagle Ford Shale in Texas, making us vulnerable to risks associated with operating in one major geographic area.

All of our midstream assets are located in the Eagle Ford Shale in Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, market limitations or interruption of the processing or transportation of natural gas, NGLs or oil.

We do not intend to obtain independent evaluations of reserves of natural gas, NGLs and oil reserves connected to Western Catarina Midstream on a regular or ongoing basis; therefore, in the future, volumes of natural gas, NGLs and oil on the gathering system could be less than we anticipate.

We have not obtained and do not intend to obtain independent evaluations of the reserves of natural gas, NGLs and oil, including those of Sanchez Energy, connected to Western Catarina Midstream on a regular or ongoing basis. Moreover, even if we did obtain independent evaluations of the reserves of natural gas, NGLs and oil connected to Western Catarina Midstream, such evaluations may prove to be incorrect. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels and operating and development costs.

Accordingly, we may not have accurate estimates of total reserves dedicated to some or all of Western Catarina Midstream or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to Western Catarina Midstream are less than we anticipate and we are unable to secure additional sources of natural gas, NGLs and oil, it could have a material adverse effect on our business, results of operations and financial condition and our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

A shortage of equipment and skilled labor in the Eagle Ford Shale could reduce equipment availability and labor productivity and increase labor and equipment costs, which could have a material adverse effect on our business and results of operations.

Gathering and processing services require special equipment and laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. Decreased levels of production and shrinking margins from lower commodity prices may result in shortages of equipment and skilled labor in the Eagle Ford Shale, as companies seek to deploy their resources in more profitable basins. If we experience shortages of necessary equipment or skilled labor in the future, our labor and equipment costs and overall productivity could be materially and adversely affected. If our equipment or labor prices increase or if we experience materially increased health and benefit costs for employees, our results of operations could be materially and adversely affected.

Distributions we receive from the Carnero JV may fluctuate from quarter to quarter as Targa, the operator, has certain discretion over the amount and timing of distributions, which could adversely affect our ability to pay cash distributions.

We received approximately $17.2 million in cash from the Carnero JV in the form of distributions during the year ended December 31, 2019. Targa, as the operator of the Carnero JV, has certain rights which permit it to affect the amount and timing of distributions to us. For example, Targa has certain discretion with regard to cash reserves and working capital adjustments that may cause the amount of our distributions to fluctuate from quarter-to-quarter. Fluctuations in the amount and timing of distributions from the Carnero JV could adversely affect our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Our participation in joint ventures exposes us to liability or harm to our reputation resulting from failures by our partner.

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 to form an expanded 50 / 50 joint venture in South Texas, Carnero JV, (2) Targa contributed 100% of the equity interest in Silver Oak II to Carnero JV, which expanded the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the Carnero Gathering Line to Carnero JV resulting in the joint venture owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, and (4) Carnero JV received a new dedication from Sanchez Energy and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Sanchez Energy's Comanche Asset pursuant to a new long-term firm gas gathering and processing agreement. We and Targa are jointly and severally liable for all liabilities and obligations of the Carnero JV. If Targa fails to perform or is financially unable to bear its portion of required capital contributions or other obligations, including liabilities stemming from claims or lawsuits, we could be required to make additional investments, provide additional services or pay more than our proportionate share of a liability to make up for Targa's shortfall. Further, if we are unable to adequately address Targa's performance issues, Sanchez Energy, the main customer on the facilities, may terminate its agreements, which could result in legal liability to us, harm our reputation and reduce cash flows generated from the Carnero Gathering Line and the Raptor Gas Processing Facility.

Increased competition from other companies that provide gathering services could have a negative impact on the demand for our services, which could adversely affect our financial results.

Our ability to flow a sufficient volume of throughput prior to and after the expiration of the Gathering Agreement to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. Our facilities compete primarily with other gathering and processing systems. Some competitors have greater financial resources than us and may now, or in the future, have access to greater supplies of natural gas, NGLs and oil than we do. Some of these competitors may expand or construct facilities that would create additional competition for the services that we provide to Sanchez Energy or other future customers. In addition, Sanchez Energy or other future customers may develop their own facilities instead of using our midstream assets. Moreover, Sanchez Energy and its affiliates are not limited in their ability to compete with us outside of the dedicated areas.

All of these competitive pressures could make it more difficult for us to retain Sanchez Energy as a customer and/or attract new customers as we seek to expand our business, which could have a material adverse effect on our business, financial condition, results of operations and ability to make cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

If third-party pipelines or other midstream facilities interconnected to our facilities become partially or fully unavailable, our operating margin, cash flows and ability to pay cash distributions could be adversely affected.

Our facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of third-party pipelines, compressor stations and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs or if any of these pipelines or other midstream facilities become unable to receive or transport natural gas, NGLs or oil, our operating margin, cash flows and ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units could be adversely affected.

We do not own the land on which Western Catarina Midstream or the Seco Pipeline is located, which could result in disruptions to our operations.

We do not own the land on which Western Catarina Midstream or the Seco Pipeline is located, and we are, therefore, subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We currently have certain rights to construct and operate our pipelines on land owned by third parties for a specific period of time and may need to obtain other rights in the future from third parties and governmental agencies to continue these operations or expand Western Catarina Midstream or the Seco Pipeline. Our loss of these rights or inability to obtain additional rights, through our inability to renew or obtain right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Our right-of-first-offer with Sanchez Energy for midstream assets is subject to risks and uncertainty, and thus may not enhance our ability to grow our business.

Pursuant to a right-of-first-offer, Sanchez Energy has agreed to offer us the right to purchase midstream assets that it desires to transfer to any unaffiliated person through 2030. Sanchez Energy is under no obligation to sell any assets to us or to accept any offer for its assets that we may choose to make. Furthermore, for a variety of reasons, we may decide not to exercise this right when it becomes available.

The acquisition of additional assets in connection with the exercise of our right-of-first-offer will depend upon, among other things, our ability to agree on the price and other terms of the sale, our ability to obtain financing on acceptable terms for the acquisition of such assets and our ability to acquire such assets on the same or better terms than third parties. We can offer no assurance that we will be able to successfully acquire any assets pursuant to this right-of-first-offer.

Our operations could be disrupted if our or SOG's information systems are hacked or fail, causing increased expenses and loss of revenue.

We face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data systems unusable, threats to the security of our facilities and infrastructure, Sanchez Energy's facilities and infrastructure or other third-party facilities and infrastructure, such as pipelines. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business.

Our business is increasingly dependent on technology infrastructure, certain critical financial, accounting and other data processing systems and other communications and information systems, including such systems of SOG that we utilize pursuant to the Services Agreement. These systems include data network and telecommunications, internet access, our website, and various computer hardware equipment and software applications, including those that are critical to the safe operations of our assets. We process transactions on a daily basis and rely upon the proper functioning of computer systems. These systems are subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cybersecurity threats to gain unauthorized access to sensitive information, cyber-attacks, which may render data systems unusable, and physical threats to the security of our and SOG's facilities and infrastructure or third-party facilities and infrastructure. If a key system were hacked or otherwise interfered with by an unauthorized access, or were to fail or experience unscheduled downtime for any reason, even if only for a short period, our financial results could be affected adversely.

Additionally, we rely on information systems across our operations, including the management of processes and transactions. A material disruption to any information systems at our operating locations, or at Sanchez Energy's or another third-party's pipelines, terminals or operating locations, may cause disruptions to our operations.

Cyber-attacks against us or others in our industry could result in additional regulations, and U.S. government warnings have indicated that infrastructure assets, including pipelines, may be specifically targeted by certain groups. These attacks include, without limitation, malicious software, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches. These attacks may be perpetrated by state-sponsored groups, "hacktivists", criminal organizations or private individuals (including employee malfeasance). Current efforts by the federal government and any potential future regulations could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

Further, our business interruption insurance may not compensate us adequately for losses that may occur. We do not carry insurance specifically for cybersecurity events; however, certain of our insurance policies may allow for coverage of associated damages resulting from such events. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results or operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Risks Related to Our Production Business

Market conditions for natural gas, NGLs and oil are highly volatile. A sustained decline in prices for these commodities could adversely affect our revenue, cash flows, profitability and growth.

Prices for natural gas, NGLs and oil fluctuate widely in response to a variety of factors that are beyond our control, such as:

- domestic and foreign supply of and demand for natural gas, NGLs and oil;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in countries producing natural gas, NGLs and oil, including terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war;
- actions of the Organization of Petroleum Exporting Countries ("OPEC") and other state-controlled oil companies relating to oil price and production controls;
- the effect of increasing liquefied natural gas and exports from the United States;
- the impact of the U.S. dollar exchange rates on prices for natural gas, NGLs and oil;
- technological advances affecting energy supply and energy consumption;
- domestic and foreign governmental regulations, including regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells, and taxation;
- the impact of energy conservation efforts and alternative fuel requirements;
- the proximity, capacity, cost and availability of production and transportation facilities for natural gas, NGLs and oil;
- events that impact global market demand, including impacts from global health epidemics and concerns, such as the coronavirus;
- the availability of refining capacity; and
- the price and availability of, and consumer demand for, alternative fuels.

Given that natural gas, NGLs and oil are global commodities, prices can also be significantly influenced by developments in other countries and markets, particularly in key consumption markets like China. For example, the ongoing coronavirus outbreak in China and other locations across the globe has resulted in a meaningful drop in the demand for crude oil and other petroleum products. Ultimately this can lead to a reduction in demand for the services we provide.

Governmental actions may also affect prices for natural gas, NGLs and oil. In the past, prices for natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue. NYMEX WTI 12 month strip price for crude oil was down more than ten percent at the end of fiscal 2019 and the NYMEX Henry Hub 12 month natural gas strip price was down approximately eight percent at the end of fiscal 2019, each when compared with fiscal 2018. Such downward volatility has negatively affected the amount of our net estimated proved reserves and has negatively affected the standardized measure of discounted future net cash flows of our net estimated proved reserves. For the years ended December 31, 2019 and 2018, we did not record impairment on our oil and natural gas properties.

In addition, our revenue, profitability and cash flows depend upon the prices of and demand for natural gas, NGLs and oil, and continued price volatility and low commodity prices, or a sustained drop in prices could negatively affect our financial results and impede our growth. In particular, sustained declines in commodity prices will:

- limit our ability to enter into commodity derivative contracts at attractive prices;
- reduce the value and quantities of our reserves, because declines in prices for natural gas, NGLs and oil would reduce the amount of natural gas, NGLs and oil that we can economically produce;
- reduce the amount of cash flows available for capital expenditures;
- limit our ability to borrow money; and
- make it uneconomical for our operating partners to commence or continue production levels of natural gas, NGLs and oil.

Drilling for and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operation, operating cash flows and any ability to pay cash distributions.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, drilling and producing operations may be curtailed, delayed or cancelled as a result of other factors, including:

- the high cost, shortages or delivery delays of drilling rigs, equipment, labor and other services;
- unexpected operational events and drilling conditions;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- piping, casing or cement failures;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss or damage to oilfield drilling and service tools;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- environmental hazards, such as natural gas leaks, oil spills, compressor incidents, pipeline ruptures and discharges of toxic gases;

- water pollution;
- fires;
- accidents or natural disasters;
- blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- loss or theft of data due to cyber-attacks; and
- third party operations.

Any of these events can increase costs or restrict the ability to drill wells and conduct operations. Any delay in the drilling program or significant increase in costs could impact our ability to generate sufficient cash flows to operate our business. Increased costs could include losses from personal injury or loss of life; damage to or destruction or loss of property, natural resources, equipment, and data; pollution; environmental contamination; loss of wells; and regulatory penalties.

Unless we replace the reserves that we produce, our existing reserves will decline, which could adversely affect our production and adversely affect our cash from operations and our ability to pay distributions to our unitholders.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary based on the reservoir characteristics and other factors. The rate of decline of our reserves and production included in our reserve report at the end of the most recently completed fiscal year will change if production from our existing wells declines in a different manner than we have estimated and may change when we make acquisitions and under other circumstances. The rate of decline may also be greater than we have estimated due to decreased capital spending or lack of available capital to make capital expenditures. Our future oil and natural gas reserves and production and, therefore, our cash flows and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically acquiring additional recoverable reserves, as we do not intend to drill new wells. We may not be able to develop or acquire additional reserves to replace our current and future production at acceptable costs, which could adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels and operating and development costs. Our independent reserve engineers do not independently verify the accuracy and completeness of information and data furnished by us. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- future oil and natural gas prices;
- production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and

- the availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk or recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure is calculated using unhedged oil and natural gas prices and is determined in accordance with the rules and regulations of the SEC (except for the impact of income taxes as we are not a taxable entity). Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual drilling and production.

The reserve estimates that we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracies in our estimates of proved reserves, future production rates and the timing of development expenditures.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves.

We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the actual prices that are received for oil and natural gas;
- actual operating costs in producing oil and natural gas;
- the amount and timing of actual production;
- the amount and timing of capital expenditures;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both production and the incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus, their actual present value. In addition, the 10% discount factor used when calculating our discounted future net cash flows in compliance with the Financial Accounting Standard Board’s Accounting Standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Future price declines or downward reserve revisions may result in write-downs of our asset carrying values, which could adversely affect our results of operations and limit our ability to borrow funds.

Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase or production data factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our properties for impairments. We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. We are required to perform impairment tests on our assets periodically and whenever events or circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore would require a write-down. We have incurred impairment charges in the past and may do so again in the future. Any impairment could be substantial and have a material adverse effect on our results of operations in the period incurred and our ability to borrow funds under our Credit Agreement, which in turn may adversely affect our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

We depend on certain key customers for sales of our oil and natural gas. To the extent these and other customers reduce the volumes of oil or natural gas they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

Our oil and natural gas production in Texas and Louisiana is marketed by the operators of our properties. To the extent these or other customers reduce the volumes of oil and natural gas that they purchase from us and are not replaced by new customers, or the market prices for oil and natural gas decline in our market areas, our revenues and cash available for distribution could decline.

Seasonal weather conditions may adversely affect our ability to conduct production activities.

Oil and natural gas operations are often adversely affected by seasonal weather conditions, primarily during periods of severe weather or rainfall, and during periods of extreme cold. Power outages and other damages resulting from tornados, ice storms, flooding and other strong storms or weather events may prevent wells from being operated in an optimal manner. These weather conditions may reduce oil and natural gas production, which could impact or reduce our future operating cash flows.

Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay operations and reduce our future operating cash flows and cash available to make future investments or to pay cash distributions.

Higher oil and natural gas prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict the ability to conduct the operations. Any significant increase in operating costs could reduce our revenues, operating cash flows and cash available to make future investments or to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Our oil and natural gas properties may be exposed to unanticipated water disposal or processing costs.

Where water produced from properties fails to meet the quality requirements of applicable regulatory agencies or wells produce water in excess of the applicable volumetric permit limit, the wells may have to be shut in or upgraded for water handling or treatment. The costs to treat or dispose of this produced water may increase if any of the following occur:

- permits cannot be renewed or obtained from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- the wells produce excess water; or
- new laws and regulations require water to be disposed of or treated in a different manner.

We may be unable to compete effectively with larger companies in the oil and natural gas industry, which may adversely affect our ability to generate sufficient revenue to allow us to pay cash distributions.

The oil and natural gas industry is intensely competitive with respect to acquiring productive properties, marketing oil and natural gas and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major independent oil and natural gas companies and possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more productive properties than our financial and personnel resources permit. Our ability to acquire additional properties will be dependent on our ability to evaluate, select and finance the acquisition of suitable properties and our ability to consummate transactions in a highly competitive environment. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties and available funds.

Many of our larger competitors not only drill for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. Our inability to compete effectively with other companies could have a material adverse effect on our business activities, financial condition, results of operations and our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Risks Related to Our Midstream and Production Businesses

As a non-operator, our development of successful operations relies extensively on third-parties, including SOG, Sanchez Energy and Targa, which could adversely affect our business, financial condition and results of operations.

We have only participated in wells, leasehold acreage and midstream assets operated by third parties, including SOG, Sanchez Energy and Targa. The success of our business operations depends on the success of such operators. If our operators are not successful in the development, exploitation, production and operating activities relating to our midstream and production businesses, or are unable or unwilling to perform, it could adversely affect our business, financial condition and results of operations.

The insolvency of an operator of any of our properties or assets, the failure of an operator of any of our properties or assets to adequately perform operations or an operator's breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations), which may not be in our best interests and could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Financing and Credit Environment

Our Credit Agreement has substantial restrictions and financial covenants and requires periodic borrowing base redeterminations.

We depend on our Credit Agreement (as defined below) for future capital needs. The Credit Agreement restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We are also required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flows from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels. Our failure to comply with any of the restrictions and covenants under the Credit Agreement could result in an event of default, which could cause all of our existing indebtedness to become immediately due and payable. Each of the following is also an event of default:

- failure to pay any principal when due or any interest, fees or other amount prior to the expiration of certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished thereunder is incorrect when made;
- failure to perform or otherwise comply with the covenants in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- any event that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;

- certain changes in control as specified in the covenants to the Credit Agreement;
- the entry of, and failure to pay, one or more adverse judgments in excess of $2.5 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and
- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.5 million in any year.

The Credit Agreement will mature on September 30, 2021. We may not be able to renew or replace the facility at similar borrowing costs, terms, covenants, restrictions or borrowing base, or with similar debt issue costs.

The amount available for borrowing at any one time under the Credit Agreement is limited to the separate borrowing bases associated with our oil and natural gas properties and our midstream assets. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is equal to the rolling four quarter EBITDA of our midstream operations multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Our Credit Agreement contains a condition to borrowing and a representation that no material adverse effect has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a material adverse effect were to occur, we would be prohibited from borrowing under the Credit Agreement and we would be in default under the Credit Agreement, which could cause all of our existing indebtedness to become immediately due and payable.

We may not be able to extend, replace or refinance our Credit Agreement on terms reasonably acceptable to us, or at all, which could materially and adversely affect our business, liquidity, cash flows and prospects.

Our Credit Agreement matures on September 30, 2021. We may not be able to extend, replace or refinance our existing Credit Agreement on terms reasonably acceptable to us, or at all, with our existing syndicate of banks or with replacement banks. In addition, we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding under our Credit Agreement upon its maturity. Any of the foregoing could materially and adversely affect our business, liquidity, cash flows and prospects.

Changes in LIBOR reporting practices or the method in which LIBOR is determined may adversely affect the market value of our current or future debt obligations, including obligations under our Credit Agreement.

As of March 13, 2020, we had approximately $144.0 million of debt outstanding under our Credit Agreement that bears interest at variable rates that use the London Interbank Offered Rate (“LIBOR”), as a benchmark rate. On July 27, 2017, the Financial Conduct Authority (the “FCA”), which regulates LIBOR, announced that it intends to stop persuading or compelling banks to submit LIBOR quotations after 2021. It is unclear whether LIBOR will cease to exist or if new methods of calculating LIBOR will be established such that it continues to exist after 2021, or whether any alternative benchmark rate will attain market acceptance as a replacement for LIBOR. It is not possible to predict the further effect of the rules of the FCA, any changes in the methods by which LIBOR is determined or any other reforms to LIBOR that may be enacted in the United Kingdom, the European Union or elsewhere. Any such developments may cause LIBOR to perform differently than in the past, or cease to exist. In addition, any other legal or regulatory changes made by the FCA, the European Commission or any other successor governance or oversight body, or future changes adopted by such body, in the method by which LIBOR is determined or the change from LIBOR to an alternative benchmark rate may result in, among other things, a sudden or prolonged increase or decrease in LIBOR, a delay in the publication of LIBOR, and changes in the rules or methodologies in LIBOR, which may discourage market participants from continuing to administer or to participate in LIBOR's determination, and, in certain situations, could result in LIBOR no longer being determined and published.

Under our Credit Agreement, if (a) the administrative agent determines that reasonable means do not exist for ascertaining LIBOR and such circumstances are unlikely to be temporary, (b) the supervisor for the administrator of LIBOR or another governmental authority having jurisdiction over the administrative agent has made a public statement identifying a date after which LIBOR shall no longer be used, or (c) new syndicated loans have started to adopt a new benchmark interest rate, then we will be required to negotiate an amendment to our Credit Agreement with the administrative agent. The use of the alternative benchmark interest rate under any such amendment may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on such debt if LIBOR was available in its current form. Further, the same costs and risks that may lead to the discontinuation or unavailability of LIBOR may make one or more of the alternative methods impossible or impracticable to determine. At this time, it is not possible to predict the effect of any establishment of any alternative benchmark rate(s) and we cannot predict what alternative benchmark rate(s) will be utilized. Any new benchmark rate will likely not replicate LIBOR exactly, and any changes to benchmark rates may have an uncertain impact on our cost of funds under our Credit Agreement. Any of these proposals or consequences could have a material adverse effect on our financing costs.

We will be required to make substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to pay cash distributions may be diminished or our financial leverage could increase.

In order to increase our asset base, we will need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations which may diminish our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units. To fund our expansion capital expenditures and investment capital expenditures, we will be required to use cash from our operations or incur borrowings. Such uses of cash from our operations will reduce cash available for distribution. Alternatively, we may sell additional common units or other securities to fund our capital expenditures. Our ability to obtain bank financing or our ability to access the capital markets for future equity or debt offerings may be limited by our or Sanchez Energy's financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions, contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could implement restrictions or limitations on our ability to pay cash distributions. For example, our Credit Agreement currently prohibits us from making distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to make or maintain cash distributions to our unitholders in the future, if any, which could materially decrease our ability to pay cash distributions. None of our general partner, Sanchez Energy or any of their respective affiliates is committed to providing any direct or indirect support to fund our growth.

Our Credit Agreement restricts us from paying any distributions on our outstanding common units.

We do not have the ability to pay distributions to our common unitholders under our Credit Agreement other than in certain limited circumstances set forth in the Credit Agreement. We have obtained waivers of Credit Agreement limitations in the past and may need to do so in the future.

Our ability to access the capital and credit markets to raise capital and borrow on favorable terms will be affected by disruptions in the capital and credit markets, which could adversely affect our operations, our ability to make acquisitions and our ability to pay cash distributions.

Disruptions in the capital and credit markets could limit our ability to access these markets or significantly increase our cost to borrow. Some lenders may increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital markets on favorable terms, our ability to make acquisitions and pay cash distributions could be affected.

We are exposed to credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers, vendors, lenders in our Credit Agreement and counterparties to our hedging arrangements. Some of our customers, vendors, lenders and counterparties may be highly leveraged and subject to their own operating and regulatory risks. For example, our largest customer, Sanchez Energy Corporation, who accounted for 86% and 71% of total revenue for the years ended December 31, 2019 and 2018, respectfully, along with certain of its subsidiaries filed the Sanchez Energy Chapter 11 Case in August of 2019. Despite our credit review and analysis, we may experience financial losses in our dealings with these and other parties with whom we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our customers, vendors, lenders or counterparties could have a material adverse impact on our business, financial condition, results of operations or ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Our future debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

We may incur substantial additional indebtedness in the future under our Credit Agreement or otherwise. Our future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, maintenance and investment capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- covenants and financial tests contained in our existing and future credit and debt instruments may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- increased cash flows required to make principal and interest payments on our indebtedness could reduce the funds that would otherwise be available to fund operations, capital expenditures, future business development or any cash distributions; and

- our debt level may make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future debt, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

Periods of inflation or stagflation, or expectations of inflation or stagflation, could increase our costs and adversely affect our business and operating results.

During periods of inflation or stagflation, our costs of doing business could increase, including increases in the variable interest rates that we pay on amounts we borrow under our Credit Agreement. As we have hedged a large percentage of our expected production volumes for 2020, the cash flows generated by that future hedged production will be capped. If any of our operating, administrative or capital costs were to increase as a result of inflation or increase in the cost of goods and services, such a cap could have a material adverse effect on our business, financial condition, results of operations, and ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

An increase in interest rates may cause the market price of our common units to decline and may increase our borrowing costs.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt or other interest-bearing securities may cause a corresponding decline in demand for riskier investments generally, including equity investments such as publicly-traded limited partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Higher interest rates may also increase the borrowing costs associated with our Credit Agreement. If our borrowing costs were to increase, our interest payments on our debt may increase, which would reduce the amount of cash available for our operating or capital activities or for any cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Risks Related to Our Cash Distributions

Our partnership agreement prohibits us from making certain distributions until all of the Class C Preferred Units are redeemed and, as a result, our ability to make, maintain and grow cash distributions is dependent on our ability to redeem the Class C Preferred Units.

Under the terms of our partnership agreement, until the first quarter in which no Class C Preferred Units remain outstanding, we are not permitted to declare or make any distributions, redemptions or repurchases in respect of, among other partnership interests, our common units. Beginning January 1, 2021, our partnership agreement provides us with the ability to redeem the Class C Preferred Units without a premium to the liquidation preference of the Class C Preferred Units. If we are unable to access the capital markets on favorable terms or otherwise secure debt or equity financing to redeem the Class C Preferred Units, our ability to redeem the Class C Preferred Units and then to make, maintain and grow cash distributions to unitholders will be materially adversely affected.

Our Credit Agreement restricts us from paying any distributions on our outstanding common units.

We do not have the ability to pay distributions to our common unitholders under our Credit Agreement other than in certain limited circumstances set forth in the Credit Agreement.

If we do not complete expansion projects or make and integrate acquisitions, our future growth may be limited.

Our ability to enhance our financial position depends, in part, on our ability to complete expansion projects and make acquisitions that result in an increase in cash generated. We may be unable to complete successful, accretive expansion projects or acquisitions for any of the following reasons:

- an inability to identify attractive expansion projects or acquisition candidates or we are outbid by competitors;
- an inability to obtain necessary rights-of-way or governmental approvals, including from regulatory agencies;
- an inability to successfully integrate the businesses that we develop or acquire;
- an inability to obtain financing for such expansion projects or acquisitions on economically acceptable terms, or at all;
- incorrect assumptions about volumes, reserves, revenues and costs, including synergies and potential growth; or
- an inability to secure adequate customer commitments to use the newly developed or acquired facilities.

We may not have sufficient available cash from operations to pay our quarterly cash distributions to Stonepeak Catarina following the establishment of cash reserves and the payment of fees and expenses.

The amount of available cash from which we may pay distributions is defined in both our Credit Agreement and our partnership agreement. The amount of available cash that we distribute is subject to the definition of operating surplus in our partnership agreement and principally depends upon the amount of cash that we generate from our operations, which will fluctuate from quarter to quarter based on numerous factors described in this Form 10-K, including this Item 1A."Risk Factors." These and other factors that affect that amount that we can distribute include:

- the amount of revenue generated from our midstream facilities;
- the amount of oil, natural gas and water that we produce;
- the demand for and the price at which we are able to sell our oil and natural gas production;
- the results of our hedging activity;
- the level of our operating costs;
- the costs that we incur to acquire midstream assets and oil and natural gas properties;
- whether we are able to continue our development activities at economically attractive costs;
- the borrowing base under our Credit Agreement as determined by our lenders;
- the amount of our indebtedness outstanding;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon;
- the amount of working capital required to operate our business and our ability to make working capital borrowings under our Credit Agreement;
- fluctuations in our working capital needs;
- the amount of cash reserves established by the Board for the proper conduct of our business; and
- the level of our maintenance capital expenditures.

As a result of these factors, we may not have sufficient available cash to pay a quarterly cash distribution to Stonepeak Catarina as the holder of all of our Class C Preferred Units. The amount of available cash that we could distribute from our operating surplus in any quarter to our unitholders may fluctuate significantly from quarter to quarter.

The amount of cash that we may have available for distribution depends primarily upon our operating cash flows and not solely on our profitability.

The amount of cash that we have available for distribution depends primarily upon our operating cash flows, including cash from reserves and working capital (which may include short-term borrowings), and not solely on our profitability, which is affected by non-cash items. As a result, we may be unable to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units even when we record net income, and we may pay cash distributions during periods when we incur net losses.

Oil and natural gas prices are very volatile. If commodity prices decline significantly for a temporary or prolonged period, our cash from operations may decline and may adversely impact our ability to invest in new midstream facilities, our financial condition and our profitability.

Our revenue, profitability and operating cash flows depend in part upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our operating cash flows and may also impact the fees generated by us from our midstream facilities. In particular, declines in commodity prices will directly reduce the value of our reserves, our operating cash flows, our ability to borrow money or raise capital and our ability to pay cash distributions and may indirectly reduce the cash flows from our midstream facilities. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and level of foreign imports of oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including those in West Africa, the Middle East and South America;
- the ability of members of OPEC to agree to and maintain oil price and production controls;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the costs, proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- the increase in the supply of natural gas due to the development of natural gas.

In the past, the prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue.

Our operations require capital expenditures, which will reduce the amount of cash that we may have available for distribution to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

We will need to make capital expenditures to maintain our facilities and infrastructure over the long-term. These expenditures could increase as a result of, among others:

- changes in labor and material costs;
- changes in leasehold and right-of-way costs; and
- government regulations relating to safety, taxation and the environment.

Our capital expenditures will vary from quarter to quarter and will reduce the amount of cash that we may have available for distribution to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Each quarter we are required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available for distribution than if actual maintenance capital expenditures were deducted.

Our partnership agreement requires us to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and potential change by the Board at least once a year. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution will be lower than if actual maintenance capital expenditures were deducted from operating surplus. If we underestimate the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates. If we do not set aside sufficient cash reserves or have available sufficient sources of financing and make sufficient expenditures to maintain our asset base, we will be unable to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Our hedging activities could result in financial losses and involve other risks, which may adversely affect our ability to pay cash distributions.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, our current practice is to hedge, subject to the terms of our Credit Agreement, a significant portion of our expected production volumes for 2020. As a result, we will continue to have direct commodity price exposure on the unhedged portion of our production volumes. The extent of our commodity price exposure is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments that we utilize are generally based on posted market prices, which may differ significantly from the actual oil and natural gas prices that we realize in our operations.

Our actual future production may be significantly higher or lower than we estimated at the time we entered into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flows from our sale or purchase of the underlying physical commodity, which may result in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps that we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

As a result of the Dodd-Frank Wall Street Reform and Consumer Protection Act and other legislation, hedging transactions and many of our contract counterparties have come under increasing governmental oversight and regulations in recent years. Although we cannot predict the ultimate impact of these laws or other proposed laws and the related rulemaking, some of which is ongoing, existing or future regulations may adversely affect the cost and availability of our hedging arrangements, including by causing our counterparties, which include lenders under our Credit Agreement, to curtail or cease their derivative activities.

Acquisitions involve potential risks that could adversely impact our future growth and our ability to pay cash distributions.

Any acquisition involves potential risks, including, among other things:

- the risk of title defects discovered after closing;
- inaccurate assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to transition and integrate successfully or timely the businesses we acquire;

- the cost of transition and integration of data systems and processes;
- potential environmental problems and costs;
- the assumptions of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns;
- increased demands on existing personnel and on our organizational structure;
- disputes arising out of acquisitions;
- customer or key employee losses of the acquired businesses; and
- the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Furthermore, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future growth and our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units.

Inadequate insurance could have a material adverse impact on our business, financial condition and results of operations.

We ordinarily maintain insurance against certain losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. In addition, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business, financial condition and results of operations.

Risks Related to Regulatory Compliance

Potential regulatory actions could increase our operating or capital costs and delay our operations or otherwise alter the way we conduct our business.

Our business activities are subject to extensive federal, state, and local regulations. Changes to existing regulations or new regulations may unfavorably impact us, our suppliers or our customers. In the United States, legislation that directly impacts the oil and natural gas industry has been proposed covering areas such as emission reporting and reductions, hydraulic fracturing of wells, the repeal of certain oil and natural gas tax incentives and tax deductions and the treatment and disposal of produced water. The EPA has also ruled that carbon dioxide, methane and other greenhouse gases endanger human health and the environment. This allows the EPA to adopt and implement regulations restricting greenhouse gases under existing provisions of the federal Clean Air Act. In addition, provisions of the Dodd-Frank Act, which regulate financial derivatives, may impact our ability to enter into derivatives or require burdensome collateral or reporting requirements. These and other potential regulations could increase our costs, reduce our liquidity, impact our ability to hedge our future oil and natural gas sales, delay our operations or otherwise alter the way that we conduct our business, negatively impacting our financial condition, results of operations and cash flows.

We are subject to federal, state, and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the production and transportation of oil and natural gas. The possibility exists that any new laws, regulations or enforcement policies could be more stringent than existing laws and could significantly increase our compliance costs. If we are not able to recover the resulting costs from insurance or through increased revenues, our ability to pay cash distributions to Stonepeak Catarina as the holder of all of our Class C Preferred Units could be adversely affected.

Our failure to obtain or maintain necessary permits could adversely affect our operations.

Our operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or leases could have a material adverse effect on our ability to develop our properties. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil and natural gas we may produce and sell.

Increased regulation of hydraulic fracturing could result in reductions or delays in the production of natural gas, NGLs and oil by Sanchez Energy, which could reduce the throughput on our facilities and adversely impact our revenues.

A substantial portion of Sanchez Energy's production of natural gas, NGLs and oil is being developed from unconventional sources, such as shale formations. These reservoirs require hydraulic fracturing completion processes to release the liquids and natural gas from the rock so it can flow through casing to the surface. Hydraulic fracturing is a well stimulation process that utilizes large volumes of water and sand (or other proppant) combined with fracturing chemical additives that are pumped at high pressure to crack open previously impenetrable rock to release hydrocarbons. Hydraulic fracturing is typically regulated by state oil and gas commissions and similar agencies. Various studies are currently underway by the EPA and other federal and state agencies concerning the potential environmental impacts of hydraulic fracturing activities. For example, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act in 2014 requesting comments related to disclosures for hydraulic fracturing chemicals. At the same time, certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation has been proposed by some members of the U.S. Congress to provide for such regulation. We cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays and process prohibitions that could reduce the volumes of liquids and natural gas that move through our facilities, which in turn could materially adversely affect our revenues and results of operations.

We may incur significant liability under, or costs and expenditures to comply with, environmental and worker health and safety regulations, which are complex and subject to frequent change.

As an owner, lessee or operator of gathering pipelines and compressor stations, we are subject to various stringent federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. These laws and regulations may impose numerous obligations that are applicable to our and our customer's operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our or our customers' operations, the imposition of specific standards addressing worker protection, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customer's operations. Failure to comply with these laws, regulations and permits may result in joint and several, strict liability and the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which our facilities pass and facilities where wastes resulting from our operations are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. We may not be able to recover all or any of these costs from insurance, the operators of our facilities and properties or other third parties. In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may interrupt our operations and limit our growth and revenues, which in turn could affect our profitability. There is no assurance that changes in or additions to public policy regarding the protection of the environment will not have a significant impact on our operations and profitability.

The operation of our facilities also poses risks of environmental liability due to leakage, migration, releases or spills from our facilities to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair or preventative or remedial measures.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in HCAs. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. Should our facilities fail to comply with DOT or comparable state regulations, we could be subject to substantial penalties and fines.

PHMSA has also published advanced notices of proposed rulemaking and notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations as well as advisory bulletins. In April 2016, PHMSA issued a notice of proposed rulemaking that would expand integrity management requirements and impose new pressure requirements on currently regulated gas transmission pipelines and would also significantly expand the regulation of gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. In addition, in 2012, PHMSA issued an advisory bulletin providing guidance on the verification of records related to pipeline maximum allowable operating pressure, which could result in additional requirements for the pressure testing of pipelines or the reduction of maximum operating pressures. The adoption of these and other laws or regulations that apply more comprehensive or stringent safety standards could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our cash flows. Please read “Item 1. Business—Governmental Regulation—Pipeline Safety Regulation” for more information.

Because we handle oil, natural gas and other petroleum products in our business, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations.

The operations of our wells, gathering systems, processing facilities, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. Certain environmental statues, including RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, and these costs may not be recoverable from insurance.

Risks Inherent in an Investment in Our Common Units

Our general partner and its affiliates will have conflicts of interest with us. They will not owe any fiduciary duties to us or our common unitholders, but instead will owe us and our common unitholders limited contractual duties, and they may favor their own interests to the detriment of us and our other common unitholders.

Manager, an affiliate of SOG, owns and controls our general partner and appoints all but two of the directors of our general partner. Although our general partner has a duty to manage us in a manner that is not adverse to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to Manager and its affiliates. Conflicts of interest will arise between SOG, Manager and their affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of Manager and its affiliates over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires Manager and its affiliates to pursue a business strategy that favors us or utilizes our assets. The directors and officers of Manager and its affiliates have a fiduciary duty to make these decisions in the best interests of the members of Manager and its affiliates, which may be contrary to our interests. Manager and its affiliates may choose to shift the focus of its investment and growth to areas not served by our assets.

- Our general partner is allowed to take into account the interests of parties other than us, such as SOG, Manager and their affiliates, in resolving conflicts of interest.

- Manager and its affiliates may be constrained by the terms of their respective debt instruments from taking actions, or refraining from taking actions, that may be in our best interests.

- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limit our general partner’s liabilities and restrict the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.

- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

- Disputes may arise under our commercial agreements with Manager, SOG and their affiliates.

- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash available for distribution.

- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which will reduce operating surplus, or an expansion or investment capital expenditure, which will not reduce operating surplus. This determination can affect the amount of cash that is distributed.

- Our general partner determines which costs incurred by it are reimbursable by us, the amount of which is not limited by our partnership agreement.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions.
- Our partnership agreement permits us to classify up to $20.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to Manager as the holder of the incentive distribution rights.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner and its controlled affiliates may exercise their right to call and purchase all of the common units not owned by them if they own more than 80% of our common units.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us, including the obligations of SOG and its affiliates under their commercial agreements with us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may elect to cause us to issue common units to Manager in connection with a resetting of the target distribution levels related to our incentive distribution rights without the approval of the Conflicts Committee or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

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 us, but not the obligation to acquire all, but not less than all, of such class of limited partner interests held by unaffiliated persons 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, 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. 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 the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its limited call right.

If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

The standstill in the Board Representation and Standstill Agreement among us, our general partner and Stonepeak Catarina will expire upon the earlier of the occurrence of a material breach of our partnership agreement and the date of which all Class C Preferred Units have been redeemed.

In connection with our August 2019 issuance of Class C Preferred Units to Stonepeak Catarina, an affiliate of Stonepeak Infrastructure Partners ("Stonepeak"), we entered into that certain Amended and Restated Board Representation and Standstill Agreement (the "Representation and Standstill Agreement"), among us, our general partner and Stonepeak Catarina. The Representation and Standstill Agreement includes a standstill provision pursuant to which Stonepeak Catarina, as the holder of all of our outstanding Class C Preferred Units, agreed that it and its affiliates would refrain from, among other things: (i) acquiring beneficial ownership of additional common units, Class C Preferred Units or other Partnership Interests (as defined in our partnership agreement); (ii) acquiring any debt or assets us or of our subsidiaries; (iii) engaging in any hostile takeover activities with respect to us or our general partner, including any merger, consolidation, recapitalization, business combination, partnership, joint venture, acquisition or similar transaction involving us or our general partner or any of our respective affiliates or properties (excluding Sanchez Energy and its properties); (iv) entering into any transaction the effect of which would be to "short" any of our securities; (v) forming, jointing or participating in any "group" (within the meaning of Section 13(d) of the Exchange Act) with respect to any voting securities of us or our affiliates in respect of any action otherwise prohibited pursuant to the standstill; (vi) calling (or participation in the calling of) a meeting of our partner for the purpose of removing (or approving the removal of) of Sanchez Midstream Partners GP LLC as our general partner and/or electing a successor general partner; (vii) "soliciting" any "proxies" (as such terms are used in the rules and regulation of the SEC) or voting for or in support of (A) the removal of Sanchez Midstream Partners GP LLC as our general partner or (B) the election of any successor general partner, or taking any action the direct effect or purpose of which would be to induce our partners to vote or provide proxies that may be voted in favor of any action contemplated by either of (A) or (B) of this subsection; (viii) seeking to advise of influence any person (within the meaning of Section 13(d)(3) if the Exchange Act) with respect to the voting of any Partnership Interest in connection with the removal (or approving the removal) of Sanchez Midstream Partners GP LLC as our general partner and/or the election of a successor general partner; (ix) issuing, inducing or assisting in the publication of any press release, media report or other publication in connection with the potential or proposed removal of Sanchez Midstream Partners GP LLC as our general partner and/or the election of a successor general partner for the Partnership; (x) advising, assisting or encouraging any third party to do any of the foregoing; or (xi) if Sanchez Midstream Partners GP LLC is removed as our general partner in violation of our partnership agreement, then participating in any way in the management, ownership and/or control of the successor general partner or the successor general partner's operation of us, other than participation by directors designated to the Board by Stonepeak Catarina in connection with the fulfillment of their duties as directors.

SOG and its affiliates may compete with us.

SOG and its affiliates may compete with us. As a result, SOG and its affiliates have the ability to acquire and operate assets that directly compete with our assets.

Manager may not allocate corporate opportunities to us.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including Manager and its executive officers and directors. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us does not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our common unitholders.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is an ineligible holder.

If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us or our subsidiaries, or we become subject to federal, state or local laws or regulations that create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the units held by the limited partner at their current market price. In order to avoid any material adverse effect on rates charged or cancellation or forfeiture of property, our general partner may require each limited partner to furnish information about their U.S. federal income tax status or nationality, citizenship or related status. If a limited partner fails to furnish information about their U.S. federal income tax status or nationality, citizenship or other related status after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible holder, our general partner may elect to treat the limited partner as an ineligible holder. An ineligible holder assignee does not have the right to direct the voting of their units and may not receive distributions in kind upon our liquidation.

The market price of our common units may fluctuate significantly, and you could lose all or part of your investment.

The market price of our common units may be influenced by many factors, some of which are beyond our control, including:

- the resolution of the Sanchez Energy Chapter 11 Case;
- provisions in our Credit Agreement which currently prohibit us from paying distributions to our common unitholders other than in certain limited circumstances set forth in our Credit Agreement;
- our quarterly or annual earnings or those of other companies in our industry;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions, including interest rates and governmental policies impacting interest rates;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in this proxy statement/prospectus and the documents incorporated herein.

Our partnership agreement replaces our general partner's fiduciary duties to our common unitholders with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replace those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will fill gaps under the partnership agreement to enforce the reasonable expectations of the partners, but only where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;

- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the Conflicts Committee; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Our partnership agreement restricts the remedies available to our common unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

The effect of eliminating fiduciary standards in our partnership agreement is that the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law will be significantly restricted. For example, our partnership agreement provides that:

- whenever our general partner, the Board or any committee thereof (including the Conflicts Committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board and any committee thereof (including the Conflicts Committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, and under our partnership agreement, a determination, other action or failure to act by our general partner and any committee thereof (including the Conflicts Committee) will be deemed to be in good faith unless the general partner, the Board or any committee thereof (including the Conflicts Committee) believed that such determination, other action or failure to act was adverse to the interests of the partnership or, with regard to certain determinations by the Board relating to the conflict transactions described below, the Board did not believe that the specified standards were met, and, except as specifically provided by our partnership agreement, neither our general partner, the Board nor any committee thereof (including the Conflicts Committee) will be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;
- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
    - approved by the Conflicts Committee of the Board, although our general partner is not obligated to seek such approval;
    - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
    - determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
    - determined by the Board to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the Conflicts Committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the Conflicts Committee and the Board determine that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth sub-bullets above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Furthermore, if any limited partner, our general partner or any person holding any beneficial interest in us brings any claims, suits, actions or proceedings (including, but not limited to, those asserting a claim of breach of a fiduciary duty) and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such limited partner, our general partner or person holding any beneficial interest in us shall be obligated to reimburse us and our “affiliates,” as defined in Section 1.1 of our partnership agreement (including our general partner, the directors and officers of our general partner, SOG and Manager) for all fees, costs and expenses of every kind and description, including, but not limited to, all reasonable attorney’s fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding.

Our partnership agreement includes exclusive forum, venue and jurisdiction provisions and limitations regarding claims, suits, actions or proceedings. By taking ownership of a common unit, a limited partner is irrevocably consenting to these provisions and limitations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue to the fullest extent permitted by applicable law for most claims, suits, actions and proceedings involving us or our officers, directors and employees and limitations regarding claims, suits, actions or proceedings. By taking ownership of a common unit, a limited partner is irrevocably consenting to these provisions and limitations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts. If a dispute were to arise between a limited partner and us or our officers, directors or employees, the limited partner may be required to pursue its legal remedies in Delaware, which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment. Furthermore, if any limited partner, our general partner or person holding any beneficial interest in us brings any claims, suits, actions or proceedings (including, but not limited to, those asserting a claim of breach of a fiduciary duty) and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such limited partner, our general partner or person holding any beneficial interest in us shall be obligated to reimburse us and our affiliates, (as defined in our partnership agreement, which includes our general partner, the directors and officers of our general partner, SOG and Manager) for all fees, costs and expenses of every kind and description, including, but not limited to, all reasonable attorneys’ fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. This provision may have the effect of increasing a unitholder’s cost of asserting a claim and therefore, discourage lawsuits against us and our general partner’s directors and officers. Because fee-shifting provisions such as these are relatively new developments in corporate and partnership law, the enforceability of such provisions are uncertain; in addition, future legislation could restrict or limit this provision of our partnership agreement and its effect of saving us and our affiliates from fees, costs and expenses incurred in connection with claims, actions, suits or proceedings.

Holders of our common units will have limited voting rights and will not be entitled to elect our general partner or its directors.

Our common unitholders have limited voting rights on matters affecting our business and, therefore, limited ability to influence management's and our general partner's decisions regarding our business. Common unitholders will have no right on an annual or ongoing basis to elect our general partner or the Board. Rather, the Board will be appointed by Manager. Furthermore, if common unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our common unitholders' ability to influence the manner or direction of management.

Our partnership agreement restricts the voting rights of common unitholders owning 20% or more of our common units.

Common unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, Stonepeak Catarina, their transferees and persons who acquired such units with the prior approval of the Board, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third-party without unitholder consent.

Our general partner is able to transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of any assets it may own without the consent of our common unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of Manager to transfer its membership interest in our general partner to a third party. The new members of our general partner would then be in a position to replace the directors and officers of our general partner in order to control the decisions taken by the Board or such officers.

The incentive distribution rights held by Manager may be transferred to a third party without unitholder consent.

Manager is able to transfer its incentive distribution rights to a third party at any time without the consent of our common unitholders. If Manager transfers its incentive distribution rights to a third party but retains its ownership interest in our general partner, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if Manager had retained ownership of the incentive distribution rights. For example, a transfer of incentive distribution rights by Manager could reduce the likelihood of SOG or its affiliates accepting offers made by us relating to assets owned by it or its affiliates, as they would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

We are able to issue additional units without common unitholder approval, which would dilute unitholder interests.

Our partnership agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to our common units that we may issue at any time without the approval of our common unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing limited partners' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each limited partnership interest may decrease;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total cash available for distribution, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;

- the relative voting strength of each previously outstanding limited partner interest may be diminished; and
- the market price of our common units may decline.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Manager, or any transferee holding a majority of the incentive distribution rights, may elect to cause us to issue common units to it in connection with a resetting of the minimum quarterly distribution and the target distribution levels related to the incentive distribution rights, without the approval of the Conflicts Committee of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

The holder or holders of a majority of the incentive distribution rights, which is currently Manager, has the right, at any time when such holders have received incentive distributions at the highest level to which they are entitled (35.5%) for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for each such quarter), to reset the minimum quarterly distribution and the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. Manager has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights will have the same rights as Manager with respect to resetting target distributions.

In the event of a reset of the minimum quarterly distribution and the target distribution levels, the holders of the incentive distribution rights will be entitled to receive, in the aggregate, the number of common units equal to that number of common units which would have entitled the holders to an average aggregate quarterly cash distribution in the prior two quarters equal to the distributions on the incentive distribution rights in the prior two quarters. We anticipate that Manager would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not otherwise be sufficiently accretive to cash distributions per common unit. It is possible, however, that Manager or a transferee could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions that it receives related to its incentive distribution rights and may therefore desire to be issued common units rather than retain the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to Manager in connection with resetting the target distribution levels.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in and outside of Delaware. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable both for the obligations of the transferor to make contributions to the partnership that were known to the transferee at the time of transfer and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

The NYSE American does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Because we are a publicly traded limited partnership, the NYSE American does not require us to have a majority of independent directors on the Board or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE American corporate governance requirements.

Tax Risks

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by states and localities. If the Internal Revenue Service ("IRS") were to treat us as a corporation for U.S. federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe that we satisfy the qualifying income requirement and will continue to be treated as a partnership for U.S. federal income tax purposes. Failure to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate income tax rate, and we would also likely pay additional state and local income taxes at varying rates. Distributions to unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits as determined for U.S. federal income tax purposes), and no income, gains, losses, deductions or credits recognized by us would flow through to the unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be reduced.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of a material amount of any these taxes in the jurisdictions in which we own assets or conduct business could substantially reduce the cash available for distribution to our unitholders.

If we were treated as a corporation for U.S. federal income tax purposes or otherwise subjected to a material amount of entity-level taxation, there would be a material reduction cash flows and after-tax return to our unitholders likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution and the target distributions may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative or legislative changes or differing judicial interpretation at any time. For example, from time to time members of the U.S. Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. We believe the income that we treat as qualifying satisfies the requirements under current regulations. However, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership for U.S. federal income tax purposes in the future.

We are unable to predict whether legislation or other tax-related proposals will ultimately be enacted. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as a partnership for U.S. federal income tax purposes. Any such change could negatively impact the value of an investment in our common units.

Our common unitholders' share of our income will be taxable to them even if they do not receive any cash distributions from us.

Common unitholders are required to pay U.S. federal income and other taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Our Credit Agreement and partnership agreement currently prohibit us from paying distributions to our common unitholders. As a result, for the foreseeable future our common unitholders will not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability due from them with respect to that income.

If the IRS contests the U.S. federal income tax positions we take, the market for our common units may be adversely impacted, and our cash available for distribution might be substantially reduced.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take, and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution and thus will be borne indirectly by our unitholders.

Pursuant to legislation applicable for partnership tax years beginning after 2017 if the IRS makes audit adjustments to our partnership tax returns, it may assess and collect any taxes (including any applicable penalties or interest) resulting from such audit adjustments directly from us. To the extent possible under these new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS in the year in which the audit is completed, or, if we are eligible, issue a revised information statement to each current and former unitholder with respect to an audited and adjusted partnership tax return. Although our general partner may elect to have our current and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. If we make payments of taxes and any penalties and interest directly to the IRS in the year in which the audit is completed, our cash available for distribution might be substantially reduced, in which case our current unitholders may bear some or all of the tax liability resulting from such audit adjustment even if the unitholders did not own units in us during the tax year under audit.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If a common unitholder sells common units, the unitholder will recognize gain or loss equal to the difference between the amount realized and its tax basis in those common units. Because distributions in excess of a unitholder’s allocable share of our net taxable income decrease the unitholder’s tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation, depletion and intangible drilling cost recapture. In addition, because the amount realized may include a unitholder’s share of our liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

Unitholders may be subject to limitations on their ability to deduct interest expense we incur.

Our ability to deduct business interest expense is limited for U.S. federal income tax purposes to an amount equal to the sum of our business interest income and 30% of our “adjusted taxable income” during the taxable year, computed without regard to any business interest income or expense, and in the case of taxable years beginning before 2022, any deduction allowable for depreciation, amortization, or depletion. Business interest expense that we are not entitled to fully deduct will be allocated to each unitholder as excess business interest and can be carried forward by the unitholder to successive taxable years and used to offset any excess taxable income allocated by us to the unitholder. Any excess business interest expense allocated to a unitholder will reduce the unitholder’s tax basis in its partnership interest in the year of the allocation even if the expense does not give rise to a deduction to the unitholder in that year.

Tax-exempt entities face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities with multiple unrelated trades or businesses cannot aggregate losses from one unrelated trade or business to offset income from another to reduce total unrelated business taxable income. As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in us to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. federal income taxes and withholding with respect to income and gain from owning our common units.

Non-U.S. persons are generally taxed and subject to U.S. federal income tax filing requirements on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be “effectively connected” with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Internal Revenue Code also imposes a U.S. federal income tax withholding obligation of 10% of the amount realized upon a non-U.S. person’s sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business.

However, application of this withholding rule to dispositions of publicly traded partnership interests has been suspended by the IRS until regulations or other guidance have been issued. It is not clear when or if such regulations or guidance will be issued. Non-U.S. persons should consult a tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we have adopted depletion, depreciation and amortization positions that may not conform with all aspects of existing U.S. Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Although Treasury regulations allow publicly traded partnerships to use a similar monthly simplifying convention, these regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for U.S. federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for U.S. federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller, and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our common units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing, character or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

As a result of investing in our common units, our unitholders may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Furthermore, our unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of such unitholder.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is included in "Part I, Item 1. Business," and is incorporated herein by reference.

The obligations under our Credit Agreement are secured by mortgages on substantially all of our assets. See "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreement," in this Form 10-K for additional information concerning our Credit Agreement.

Item 3. 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 Sanchez Energy Chapter 11 Case have been filed against us. However, on March 13, 2020, the Unsecured Committee filed the March 13 Motion. The relief sought in the March 13 Motion is to grant the Unsecured Committee derivative standing to prosecute claims that Sanchez Energy allegedly has against the Partnership and others, including, but not limited to, claims to recharacterize or avoid the Catarina Transaction, the Carnero Gathering Transaction and the Carnero Processing Transaction. While we do not believe these claims have any merit, if such claims are filed and prosecuted, the cost to defend against such claims and any judgment entered against us could have a material and adverse impact on our business, financial condition and operating results. For additional information about the Sanchez Energy Chapter 11 Case please see https://cases.primeclerk.com/sanchezenergy and dm.epiq11.com/case/sanchez/info. Information contained on these websites, however, is not incorporated into or otherwise a part of this Form 10-K.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are listed on the NYSE American under the symbol "SNMP."

Holders

The number of unitholders of record of our common units was approximately 53 on March 13, 2020, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

Distributions

Rationale for Our Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a fundamental judgment that our unitholders generally will be better served by our distributing rather than retaining our available cash. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions in any amount, and our general partner has considerable discretion to determine the amount of our available cash each quarter. Our partnership agreement generally defines "available cash" as cash on hand at the end of a quarter after the payment of expenses, less the amount of cash reserves established by our general partner to provide for the conduct of our business and to comply with applicable law, any of our debt instruments or other agreements or to provide for future distributions to our unitholders for any one or more of the next four quarters. Our available cash may also include, if our general partner so determines, all or any portion of the cash on hand immediately prior to the date of distribution of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute to our unitholders than would be the case if we were subject to entity-level federal income tax. If we do not generate sufficient available cash from our operations, we may, but are under no obligation to, borrow funds to pay distributions to our unitholders.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that we will make quarterly cash distributions to our unitholders. We do not have a legal or contractual obligation to pay quarterly distributions or any other distributions except as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions and uncertainties, including the following:

- Until the first quarter in which no Class C Preferred Units remain outstanding, we are not permitted to declare or make any distributions in respect to our common units.

- Our cash distribution policy is subject to restrictions on distributions under our Credit Agreement, which contains financial tests that we must meet and covenants that we must satisfy. Should we be unable to meet these financial tests or satisfy these covenants or if we are otherwise in default under our Credit Agreement, we will be prohibited from making cash distributions notwithstanding our cash distribution policy.

- Our general partner has the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish. Any decision to establish cash reserves made by our general partner in good faith will be binding on our unitholders.

- Prior to making any distribution on our common units, and pursuant to the Services Agreement, we will pay Manager an administrative fee and reimburse our general partner and its affiliates, including Manager, for all direct and indirect expenses that they incur on our behalf. Neither our partnership agreement nor the Services

Agreement limits the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses may include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates may impact our ability to pay distributions to our unitholders.

- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to make cash distributions contained therein, may be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by Sanchez Energy and its affiliates, if any).

- Even if our cash distribution policy is not modified or revoked, the decisions regarding the amount of distributions to pay under our cash distribution policy and whether to pay any distribution are determined by our general partner, taking into consideration the terms of our partnership agreement.

- Under Section 17-607 of the Delaware Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to a shortfall in cash flows attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our outstanding debt, tax expenses, working capital requirements or anticipated cash needs.

- If we make distributions out of capital surplus, as opposed to operating surplus, any such distributions would constitute a return of capital and would result in a reduction in the minimum quarterly distribution and the target distribution levels. We do not anticipate that we will make any distributions from capital surplus.

- Our ability to make distributions to our unitholders depends on the performance of our assets and subsidiaries and the ability of our subsidiaries to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of future indebtedness, applicable state laws and other laws and regulations.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Incentive Distribution Rights

All of the incentive distribution rights are held by Manager. Incentive distribution rights represent the right to receive increasing percentages (13%, 23% and 35.5%) of quarterly distributions from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved.

For any quarter in which we have distributed cash from operating surplus to our common unitholders in an amount equal to the minimum distribution and distributed cash from surplus to the outstanding common units to eliminate any cumulative arrearages in payment of the minimum quarterly distribution, then we will distribute any additional cash from operating surplus for that quarter among the unitholders and the incentive distribution rights holders in the following manner:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Per Common Unit	Common Unitholders	Manager (as Holder of Incentive Distribution Rights)
Minimum Quarterly Distribution	up to $0.50	100.00%	0.00%
First Target Distribution	above $0.50 up to $0.575	100.00%	0.00%
Second Target Distribution	above $0.575 up to $0.625	87.00%	13.00%
Third Target Distribution	above $0.625 up to $0.875	77.00%	23.00%
Thereafter	above $0.875	64.50%	35.50%

Manager’s right to receive incentive distributions is reduced by a percentage equal to the number of common units held by Sanchez Energy and its affiliates resulting from the common unit issuance made to SN UR Holdings, LLC, a subsidiary of Sanchez Energy, in November 2016, divided by all common units outstanding as of the time of distribution.

Securities Authorized for Issuance Under Equity Compensation Plans

See “Part III, Item 12. Security Ownership of Certain Benefits Owners and Management and Related Unitholder Matters” for information regarding our equity compensation plan as of December 31, 2019.

Recent Sales of Unregistered Securities

In connection with providing services under the Services Agreement for the year ended December 31, 2019, the Partnership issued 2,576,760 common units to Manager. See Note 14 "Related Party Transactions" of our Notes to Consolidated Financial Statements for additional information related to the Services Agreement. The issuance of these common units was exempt from the registration requirements of the Securities Act of 1933, as amended (the “Securities Act”), pursuant to section 4(a)(2) thereof as a transaction by an issuer not involving a public offering.

Purchases of Equity Securities by Us and our Affiliates

No common units were repurchased by us during the fourth-quarter 2019.

Default Upon Senior Securities

There were no defaults on senior securities for the years ended December 31, 2019 or 2018.

Item 6. Selected Financial Data

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information required by this Item.

Item 7. 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 this 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, and reversionary working interests and other production assets in Texas and Louisiana. On June 2, 2017, we changed our name to Sanchez Midstream Partners LP from Sanchez Production Partners LP. Manager owns our general partner and all of our incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol "SNMP."

Significant Operational Factors in 2019

Some key highlights of our business activities for the year ended December 31, 2019 were:

- On Western Catarina Midstream, the Partnership implemented two tariff rate increases on throughput volumes from approximately 71,000 net acres on Sanchez Energy's Catarina Asset which are not currently dedicated under the Gathering Agreement; and
- For the year ended December 31, 2019, we reduced cash related general and administrative expense by $2.6 million, or 20%, compared to the same period 2018.

How We Evaluate Our Operations

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

- our throughput volumes on gathering systems upon 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 Catarina Transaction, our management began to analyze our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within Sanchez Energy's Catarina Asset, which consists of approximately 106,000 net acres in Dimmit, La Salle and Webb counties in 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 Sanchez Energy on the acreage dedicated to Western Catarina Midstream, our ability to secure volumes from Sanchez Energy from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure. Construction of the Seco Pipeline was completed in August 2017, and throughput volumes are dependent on gas processed at the Raptor Gas Processing Facility and demand for dry gas in markets in South Texas.

Future throughput volumes on the pipeline are dependent on execution of a new transportation agreement with Sanchez Energy or execution of an agreement with a third party.

Operating Expenses

Our management seeks to maximize Adjusted EBITDA, a non-GAAP financial measure, in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (which generally consists of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, among other items), compression expense, ad valorem taxes and other operating costs, some of which will be independent of our oil and natural gas production or the throughput volumes on the 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 U.S. generally accepted accounting principles (“GAAP”), we use Adjusted EBITDA, a non-GAAP financial measure, in this Form 10-K. We believe that non-GAAP financial measures are helpful in understanding our past financial performance and potential future results, particularly in light of the effect of various transactions effected by us. We define Adjusted EBITDA as net income (loss) adjusted by: (i) interest (income) expense, net, which includes interest expense, interest expense net (gain) loss on interest rate derivative contracts, and interest (income); (ii) income tax expense (benefit); (iii) depreciation, depletion and amortization; (iv) asset impairments; (v) accretion expense; (vi) (gain) loss on sale of assets; (vii) unit-based compensation expense; (viii) unit-based asset management fees; (ix) distributions in excess of equity earnings; (x) (gain) loss on mark-to-market activities; (xi) commodity derivatives settled early; (xii) (gain) loss on embedded derivatives; and (xiii) acquisition and divestiture costs.

Adjusted EBITDA is used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess: (i) the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and (iii) our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

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

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

	Years Ended December 31,	
	2019	2018
Net income (loss)	$ (51,142)	$ 15,691
Adjusted by:		
Interest expense, net	39,789	10,961
Income tax expense	202	190
Depreciation, depletion and amortization	25,333	25,987
Asset impairments	32,119	—
Accretion expense	526	497
Gain on sale of assets	—	(3,186)
Unit-based compensation expense	1,351	1,938
Unit-based asset management fees	7,321	8,646
Distributions in excess of equity earnings	11,352	9,754
Gain on mark-to-market activities	(1,183)	(3,229)
Acquisition and divestiture costs	—	2,150
Adjusted EBITDA	$ 65,668	$ 69,399

Significant Operational Factors

Throughput. The following table sets forth selected throughput data pertaining to the Midstream segment for the years ended December 31, 2019 and 2018:

	Years Ended December 31,	
	2019	2018
Western Catarina Midstream:		
Oil (MBbls/d)	11.1	12.8
Natural gas (MMcf/d)	131.7	157.2
Water (MBbls/d)	5.5	11.0
Seco Pipeline:		
Natural gas (MMcf/d)	1.9	35.4

Production. Our production for the year ended December 31, 2019 was approximately 309 MBoe, or an average of 847 Boe/d, compared to approximately 439 MBoe, or an average of 1,203 Boe/d, for the same period in 2018.

Capital Expenditures. For the year ended December 31, 2019, we spent approximately $0.5 million in capital expenditures, consisting of $0.5 million related to the development of Western Catarina Midstream and less than $0.1 million related to the development of the Seco Pipeline. For the year ended December 31, 2018, we spent approximately $2.0 million in capital expenditures, consisting of $1.4 million related to the development of Western Catarina Midstream and $0.6 million related to the development of the Seco Pipeline.

Hedging Activities. For the year ended December 31, 2019, the non-cash mark-to-market loss for our commodity derivatives was approximately $4.7 million, compared to a gain of $2.7 million for the same period in 2018.

Results of Operations by Segment

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):

	Years Ended December 31, 2019	Years Ended December 31, 2018	Variance	
Revenues:				
Gathering and transportation sales	$ 6,825	$ 6,651	$ 174	3%
Gathering and transportation lease revenues	59,090	53,025	6,065	11%
Total gathering and transportation sales	65,915	59,676	6,239	10%
Operating costs:				
Lease operating expenses	1,499	1,145	354	31%
Transportation operating expenses	11,553	12,316	(763)	(6%)
Depreciation and amortization	21,391	21,189	202	1%
Asset impairments	32,119	—	32,119	NM [(a)]
Accretion expense	326	299	27	9%
Total operating expenses	66,888	34,949	31,939	91%
Other income:				
Earnings from equity investments	2,831	12,859	(10,028)	(78%)
Operating income	$ 1,858	$ 37,586	$ (35,728)	(95%)

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

Gathering and transportation sales. Gathering and transportation sales increased by approximately $0.2 million to approximately $6.8 million for the year ended December 31, 2019, compared to approximately $6.7 million during the same period in 2018.

Gathering and transportation lease revenues. Gathering and transportation lease revenues increased by approximately $6.1 million, or 11%, to approximately $59.1 million for the year ended December 31, 2019, compared to approximately $53.0 million during the same period in 2018. This increase was primarily the result of an increase in the rate charged for natural gas transported on Western Catarina Midstream that was produced from outside the dedicated acreage under the Gathering Agreement.

Lease operating expenses. Lease operating expenses, which include ad valorem taxes, increased approximately $0.4 million, or 31%, to approximately $1.5 million for the year ended December 31, 2019, compared to approximately $1.1 million during the same period in 2018.

Transportation operating expenses. Our transportation operating expenses generally consist of gathering and transportation operating expenses, labor, vehicles, supervision, minor maintenance, tools, supplies, and integrity management expenses. Our transportation operating expense decreased approximately $0.8 million, or 6%, to approximately $11.6 million for the year ended December 31, 2019, compared to approximately $12.3 million during the same period in 2018.

Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets. Our depreciation and amortization expense increased approximately $0.2 million, or 1%, to approximately $21.4 million for the year ended December 31, 2019, compared to approximately $21.2 million during the same period in 2018.

Impairment expense. For the year ended December 31, 2019, our non-cash impairment charge was approximately $32.1 million, to impair the Seco Pipeline. We received a written notice from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective as of February 12, 2020. See Note 21 "Subsequent Events" of our Notes to

Consolidated Financial Statements for additional information on the termination of the Seco Pipeline Transportation Agreement. We did not record impairment on our gathering and transportation assets during the year ended December 31, 2018.

Earnings from equity investments. Earnings from equity investments decreased approximately $10.0 million, or 78%, to approximately $2.8 million for the year ended December 31, 2019, compared to approximately $12.9 million for the same period in 2018. This decrease in earnings was primarily the result of lower throughput during the year ended December 31, 2019.

Production Operating Results

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

	Years Ended December 31, 2019	Years Ended December 31, 2018	Variance	
Revenues:				
Natural gas sales at market price	$ 424	$ 1,037	$ (613)	(59%)
Natural gas hedge settlements	94	(37)	131	NM [a]
Natural gas mark-to-market activities	165	(47)	212	NM [a]
Natural gas total	683	953	(270)	(28%)
Oil sales	13,543	19,872	(6,329)	(32%)
Oil hedge settlements	807	(1,330)	2,137	NM [a]
Oil mark-to-market activities	(4,838)	2,730	(7,568)	NM [a]
Oil total	9,512	21,272	(11,760)	(55%)
NGL sales	539	1,709	(1,170)	(68%)
Total revenues	10,734	23,934	(13,200)	(55%)
Operating costs:				
Lease operating expenses	5,879	6,719	(840)	(13%)
Production taxes	621	1,104	(483)	(44%)
Gain on sale of assets	—	(3,186)	3,186	NM [a]
Depreciation, depletion and amortization	3,942	4,798	(856)	(18%)
Accretion expense	200	198	2	1%
Total operating expenses	10,642	9,633	1,009	10%
Operating income	$ 92	$ 14,301	$ (14,209)	(99%)

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

	Years Ended December 31, 2019	Years Ended December 31, 2018	Variance	
Net production:				
Natural gas (MMcf)	231	434	(203)	(47%)
Oil production (MBbl)	228	296	(68)	(23%)
NGLs (MBbl)	42	71	(29)	(41%)
Total production (MBoe)	309	439	(130)	(30%)
Average daily production (Boe/d)	847	1,203	(356)	(30%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 2.24	$ 2.30	$ (0.06)	(3%)
Natural gas price per Mcf without hedge settlements	$ 1.84	$ 2.39	$ (0.55)	(23%)
Oil price per Bbl with hedge settlements	$ 62.94	$ 62.64	$ 0.30	0%
Oil price per Bbl without hedge settlements	$ 59.40	$ 67.14	$ (7.74)	(12%)
NGL price per Bbl without hedge settlements	$ 12.83	$ 24.07	$ (11.24)	(47%)
Total price per Boe with hedge settlements	$ 49.86	$ 48.41	$ 1.45	3%
Total price per Boe without hedge settlements	$ 46.94	$ 51.52	$ (4.58)	(9%)
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 21.04	$ 17.82	$ 3.22	18%
Lease operating expenses	$ 19.03	$ 15.31	$ 3.72	24%
Production taxes	$ 2.01	$ 2.51	$ (0.50)	(20%)
Depreciation, depletion and amortization	$ 12.76	$ 10.93	$ 1.83	17%

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

Production, For the year ended December 31, 2019, 74% of our production was oil, 14% was NGLs and 12% was natural gas compared to the year ended December 31, 2018, where 67% of our production was oil, 16% was NGLs and 17% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2018 that were rich in natural gas. Combined production has decreased by 130 MBoe for the year ended December 31, 2019, primarily due to the closings during 2018 of the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

Sales of natural gas, NGLs and oil. Unhedged oil sales decreased $6.3 million, or 32%, to $13.5 million for the year ended December 31, 2019, compared to approximately $19.9 million for the same period in 2018. Sales of NGLs decreased approximately $1.2 million, or 68%, to $0.5 million for the year ended December 31, 2019, compared to approximately $1.7 million for the same period in 2018. Unhedged natural gas sales decreased approximately $0.6 million, or 59%, to approximately $0.4 million for the year ended December 31, 2019, compared to approximately $1.0 million for the same period in 2018. The total decrease in sales of natural gas, NGLs and oil for the year ended December 31, 2019 was primarily the result of the same factors described under “Production” above as well as a decrease in average sales prices.

Including hedges and mark-to-market activities, our total production-related revenue decreased approximately $13.2 million for the year ended December 31, 2019, compared to the same period in 2018. This decrease was primarily the result of approximately $7.6 million of losses on oil mark-to-market activities and a decrease in oil sales of approximately $6.3 million.

The following tables provide an analysis of the impacts of changes in production volumes and average realized prices between the periods on our unhedged revenues for the year ended December 31, 2019 compared to the year ended December 31, 2018 (in thousands, except average sales prices and volumes):

	2019 Average Sales Price	2018 Average Sales Price	Average Sales Price Difference	2019 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 1.84	$ 2.39	$ (0.55)	231	$ (127)
Oil (MBbl)	$ 59.40	$ 67.14	$ (7.74)	228	$ (1,765)
NGLs (MBbl)	$ 12.83	$ 24.07	$ (11.24)	42	$ (472)
Total oil equivalent (MBoe)	$ 46.94	$ 51.52	$ (4.58)	309	$ (2,364)

	2019 Production Volume	2018 Production Volume	Production Volume Difference	2018 Average Sales Price	Revenue Decrease due to Production
Natural gas (MMcf)	231	434	(203)	$ 2.39	$ (485)
Oil (MBbl)	228	296	(68)	$ 67.14	$ (4,565)
NGLs (MBbl)	42	71	(29)	$ 24.07	$ (698)
Total oil equivalent (MBoe)	309	439	(130)	$ 51.52	$ (5,748)

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 year ended December 31, 2019 by approximately $1.5 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas revenues. For the year ended December 31, 2019, the non-cash mark-to-market losses were approximately $4.7 million, compared to gains of approximately $2.7 million for the same period in 2018. The 2019 non-cash mark-to-market loss resulted from higher future expected oil prices compared to the settlement prices on our oil fixed price basis swaps. Cash settlements received for our commodity derivatives were approximately $0.9 million for the year ended December 31, 2019, compared to settlements paid of approximately $1.4 million for the year ended December 31, 2018.

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

Lease operating expenses. Lease operating expenses decreased approximately $0.8 million, or 13%, to approximately $5.9 million for the year ended December 31, 2019, compared to $6.7 million for the same period in 2018. This decrease in operating expenses was primarily due to the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture that closed during 2018.

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 the production of natural gas, NGLs and oil increases or decreases, our depletion expense would increase or decrease as well, respectively.

Our depreciation, depletion and amortization expense for the year ended December 31, 2019 was approximately $3.9 million, compared to approximately $4.8 million for the same period in 2018. The decrease was primarily the result of the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture that closed during 2018. Our non-oil and natural gas properties are depreciated using the straight-line basis.

Impairment expense. For the years ended December 31, 2019 and 2018, we did not record impairment on our oil and natural gas properties.

Consolidated Earnings Results

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

	Years Ended December 31, 2019	Years Ended December 31, 2018	Variance	
Reconciliation of segment operating income to net income (loss):				
Total production operating income	$ 92	$ 14,301	$ (14,209)	(99%)
Total midstream operating income	1,858	37,586	(35,728)	(95%)
Total segment operating income	1,950	51,887	(49,937)	(96%)
General and administrative expense	(17,610)	(23,653)	6,043	(26%)
Unit-based compensation expense	(1,351)	(1,938)	587	(30%)
Interest expense, net	(39,789)	(10,961)	(28,828)	NM [(a)]
Other income	5,860	546	5,314	NM [(a)]
Income tax expense	(202)	(190)	(12)	6%
Net income (loss)	$ (51,142)	$ 15,691	$ (66,833)	NM [(a)]

(a) Amounts 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 approximately $6.0 million, or 26%, to approximately $17.6 million for the year ended December 31, 2019, compared to approximately $23.7 million for the same period in 2018. The decrease was primarily the result of reduced salaries and wages, as well as reduced asset management fees.

Unit-based compensation expense. Unit-based compensation expense decreased approximately $0.6 million, or 30%, to approximately $1.4 million for the year ended December 31, 2019, compared to approximately $1.9 million for the same period in 2018. This decrease was the result of a substantial decline in the price of our common units on the NYSE American during the two year period ended December 31, 2019.

Interest expense, net. Interest expense increased approximately $28.8 million, to approximately $39.8 million for the year ended December 31, 2019, compared to approximately $10.9 million for the same period in 2018. This increase was the result of the issuance of the Class C Preferred Units and the Warrant on August 2, 2019. The accrual of distributions on the Class C Preferred Units as well as the mark-to-market impact of the Warrant are charges to interest expense. Cash interest expense for the year ended December 31, 2019 was approximately $9.2 million compared to approximately $10.2 million for the same period in 2018. See Note 17. "Partner's Capital" of our Notes to Consolidated Financial Statements for additional information related to Class C Preferred Units and the Warrant.

Other income (expense). Other income was approximately $5.9 million for the year ended December 31, 2019, compared to approximately $0.5 million for the same period in 2018, resulting from changes in the fair value measurement of the earnout derivative.

Income tax expense. Income tax expense was approximately $0.2 million for the years ended December 31, 2019, and 2018, respectively.

Liquidity and Capital Resources

As of December 31, 2019, we had approximately $5.1 million in cash and cash equivalents and $15.0 million available for borrowing under the Credit Agreement in effect on such date, as discussed further below. During the years ended December 31, 2019 and 2018, we paid approximately $9.2 million and $9.8 million, respectively, in cash for interest on borrowings under our Credit Agreement, of which approximately $0.2 million was related to the fee on undrawn commitments during the year ended December 31, 2019.

Our capital expenditures during the year ended December 31, 2019 were funded with cash on hand. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional 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 quarterly cash distributions, if any.

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 Ninth Amendment to Third Amended and Restated Credit Agreement (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.

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 December 31, 2019, the borrowing base under the Credit Agreement was $235.5 million and we had $150.0 million of debt outstanding, consisting of $145.0 million under the Term Loan and $5.0 million under the Revolving Loan. We are required to make mandatory payments of outstanding principal on the Term Loan of $10 million per fiscal quarter. The maximum revolving credit amount is $20.0 million which left us with $15.0 million in unused borrowing capacity at December 31, 2019. There were no letters of credit outstanding under our Credit Agreement as of December 31, 2019.

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 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 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 December 31, 2019, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Sources of Debt and Equity Financing

As of December 31, 2019, we had $5.0 million of debt outstanding under the Revolving Loan, leaving us with $15.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement at December 31, 2019. Our Credit Agreement matures on September 30, 2021.

In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately $1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015, as supplemented by that certain prospectus supplement filed with the SEC on April 6, 2017.

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 December 31, 2019, summarize, for the periods indicated, our hedges currently in place through December 31, 2020. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps—NYMEX (Henry Hub)

	Three Months Ended (volume in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85

MTM Fixed Price Basis Swaps–West Texas Intermediate (WTI)

	Three Months Ended (volume in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50

Operating Cash Flows

We had net cash flows provided by operating activities for the year ended December 31, 2019, of approximately $58.0 million, compared to net cash flows provided by operating activities of approximately $66.9 million for the same period in 2018. This decrease was primarily related to the impact of lower average commodity prices between the periods resulting in lower production for the period of approximately $5.7, as well as a decrease of approximately $2.4 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 year ended December 31, 2019 of approximately $1.4 million, consisting of approximately $1.0 million related to midstream activities, including pipeline construction, and contributions to Carnero JV totaling approximately $0.2 million.

Our net cash flows provided by investing activities for the year ended December 31, 2018 were approximately $2.3 million, consisting of approximately $2.5 million related to midstream activities, including pipeline construction, and contributions to Carnero JV totaling approximately $2.8 million. These outflows were offset by approximately $7.7 million related to proceeds from sales of oil and natural gas properties.

Financing Activities

Net cash flows used in financing activities was approximately $54.4 million for the year ended December 31, 2019. During the year ended December 31, 2019, we distributed (i) approximately $17.7 million to Stonepeak Catarina, as the holder of all of our previously outstanding Class B Preferred Units and, starting with the distribution for the quarter ended June 30, 2019, the holder of all of our outstanding Class C Preferred Units, and (ii) approximately $5.2 million to our common unitholders. Additionally, we paid approximately $0.2 million in costs associated with the Exchange (as defined herein) and repaid $34.0 million of borrowings under the Credit Agreement.

Net cash flows used in financing activities were approximately $66.6 million for the year ended December 31, 2018. During the year ended December 31, 2018, we distributed approximately $33.3 million to Stonepeak Catarina, as the holder of all of our outstanding Class B Preferred Units, and approximately $23.2 million to our common unitholders.

Additionally, we paid approximately $0.1 million in offering costs and repaid $11.0 million of borrowings under the Credit Agreement.

Off-Balance Sheet Arrangements

As of December 31, 2019, 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, Sanchez Energy, the sale of oil and natural gas and our use of derivatives. On August 11, 2019, the Sanchez Energy Chapter 11 Case was filed. No assurances can be given as to the timing or outcome of this process. As of December 31, 2019, we had no past due receivables from Sanchez Energy, and through December 31, 2019, we have not suffered any significant losses with our counterparties as a result of nonperformance. However, on January 13, 2020, we received written notice of termination from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective February 12, 2020. Given our midstream focus, our primary credit exposure relates to the creditworthiness of the counterparties under our gathering and processing agreements. Sanchez Energy, whose earned revenues contribute to our midstream segment, accounted for 86% of total revenue for the year ended December 31, 2019. Any development that materially and adversely affects Sanchez Energy's operations or financial condition 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 Sanchez Energy, please read "Part I, Item 1A. Risk Factors."

Certain key counterparty relationships are described below:

Derivative Counterparties

As of December 31, 2019, our derivatives were with ING, Comerica and Royal Bank of Canada, all of whom are lenders in our Credit Agreement. 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. As of December 31, 2019, each of these financial institutions had an investment grade credit rating.

Credit Agreement

As of December 31, 2019, the banks and their percentage commitments in our Credit Agreement were: Royal Bank of Canada (13%), BBVA USA f/k/a Compass Bank (12%), Trust Bank f/k/a SunTrust Bank (12%), Capital One, National Association (12%), Comerica Bank (12%), Citibank, N.A. (9%), Credit Suisse AG, Cayman Islands (9%), ING Capital LLC (9%), CIT Bank, N.A. (9%) and Macquarie Investments US Inc (5%). As of December 31, 2019, each of these financial institutions had an investment grade credit rating.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

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 Note 2 “Basis of Presentation and Summary of Significant Accounting Policies” to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

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. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

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. As more fully described in Note 8 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

All other properties, including gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

Estimated asset retirement costs are recognized when the asset is acquired or placed in service. Costs associated with oil and natural gas properties are amortized over proved reserves using the units-of-production method. Costs associated with gathering and transportation assets are depreciated using the straight-line method over the useful lives of the asset. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Oil and natural gas properties are reviewed for impairment 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. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 8 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements for additional information.

Gathering and transportation assets are reviewed for impairment 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. Refer to Note 8 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements for additional information.

Reserves of Natural Gas, NGLs and Oil

Our estimate of proved reserves is based on the quantities of natural gas, NGLs and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of the reserve report prepared by Ryder Scott, an independent oil and natural gas consulting firm. On an annual basis, our proved reserve estimates and the reserve report prepared by Ryder

Scott are reviewed by the Audit Committee and the Board. Our financial statements for 2019 and 2018 were prepared using Ryder Scott's estimates of our proved reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the actual quantities of oil and natural gas eventually recovered.

Recent Accounting Pronouncements and Accounting Changes

See Note 2 "Basis of Presentation and Summary of Significant Accounting Policies" to our consolidated financial statements included in this report for information on new accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information required by this Item.

Item 8. Financial Statements and Supplementary Data

The information required by this Item is included in this report as set forth in the "Index to Consolidated Financial Statements" beginning on page F-1 of this Form 10-K and is incorporated by reference herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with the Partnership have been detected. These inherent limitations include error by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the principal executive officer and principal financial officer of our general partner, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. The principal executive officer and principal financial officer of our general partner have concluded that our current disclosure controls and procedures were effective as of December 31, 2019 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2019, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Reports of Management

Financial Statements

The management of our general partner is responsible for the information and representations in our financial statements. We prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management’s best estimates and judgments of known conditions.

The Audit Committee, which consists of three independent directors, meets periodically with management, our internal auditor and KPMG LLP to review the activities of each in discharging their responsibilities. Our internal auditor and KPMG LLP have free access to the Audit Committee.

Management’s Report on Internal Control Over Financial Reporting

Our management, under the direction of the principal executive officer and principal financial officer of our general partner, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Exchange Act.

Our system of internal control over financial reporting is designed to provide reasonable assurance to our management and the Board regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of our general partner conducted an evaluation of the effectiveness of our internal control over financial reporting using the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the Board regarding achievement of an entity’s financial reporting objectives. Based upon the evaluation under this framework, management concluded that our internal control over financial reporting was effective as of December 31, 2019.

Report of Independent Registered Public Accounting Firm

Please see Report of Independent Public Accounting Firm under “Part II, Item 8. Financial Statements and Supplementary Data” of this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table shows information for members of the Board and the executive officers of our general partner as of March 13, 2020. All of the directors of our general partner are elected by Manager, as the sole member of our general partner, except for two persons who are appointed by Stonepeak Catarina pursuant to the Representation and Standstill Agreement. Members of the Board hold office until their successors have been elected or qualified or until the earlier of their death, incapacity, resignation or removal. Executive officers hold office at the discretion of, and may be removed by, the Board.

Name	Age	Position with Sanchez Midstream Partners LP
Alan S. Bigman	52	Independent Director
Kirsten A. Hink	53	Chief Accounting Officer
Jack Howell	33	Director
Richard S. Langdon	69	Independent Director
G.M. Byrd Larberg	67	Independent Director
Antonio R. Sanchez, III	46	Director; Chairman of the Board
Eduardo A. Sanchez	40	Director
Patricio D. Sanchez	39	Director; President & Chief Operating Officer
Luke R. Taylor	42	Director
Charles C. Ward	59	Chief Financial Officer & Secretary
Gerald F. Willinger	52	Director; Chief Executive Officer

Alan S. Bigman was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in July 2014. Mr. Bigman is an independent member of the Conflicts Committee of our general partner and is the Chair of the Audit Committee of our general partner. Mr. Bigman currently serves as an independent non-executive director and chairman of the audit committee of a $1.5 billion dollar privately held chemicals company. His extensive board experience also includes Basell Polyolefins, an international chemical producer and predecessor of LyondellBasell, where he served as a non-executive director before his appointment as Chief Financial Officer, and Svyazinvest, then Russia's largest telecom company, as well as several others. Mr. Bigman's executive experience includes fourteen years in positions with Access Industries, a privately-held, U.S.-based industrial group, and in senior positions with its portfolio companies. From June 1996 to March 1998, Mr. Bigman was Senior Vice President of Access Industries, overseeing strategic investments. From March 1998 until September 2003, Mr. Bigman served as Vice President and Director of Corporate Finance of Tyumen Oil Company (TNK), a major Russian oil and gas producer and refiner, where he raised over $5 billion to finance the growth of the company from its privatization in 1997 through a sale of a 50% stake to British Petroleum (BP) in 2003, creating TNK-BP, a $20 billion joint venture. From 2003 to 2004, he served as Vice President and Director of Corporate Finance for SUAL, a large Russian aluminum smelter, where he reorganized the finance function and executed strategic merger transactions. From September 2004 until December 2005, Mr. Bigman rejoined Access Industries as Senior Vice President. In January 2006, Mr. Bigman was appointed Chief Financial Officer of Basell Polyolefins, an international chemicals company based in The Netherlands, where he served through 2007 and co-led the acquisition of Lyondell to create one of the largest global chemical companies. In January 2008 Mr. Bigman was appointed Chief Financial Officer of LyondellBasell Industries, the successor company to Basell Polyolefins and Lyondell. LyondellBasell's US operations filed for bankruptcy in January 2009. Mr. Bigman continued to serve as Chief Financial Officer until August 2009, and worked for the company in a project role through March 2010. From 2011 through 2012, he served on a project basis as Director, Capital Markets and M&A of KCAD Deutag, an oilfield services company based in Aberdeen, UK, where he was responsible for reorganizing and staffing the company's finance, corporate development and tax functions.

Kirsten A. Hink was elected Chief Accounting Officer of our general partner in May 2015. Mrs. Hink has served as Senior Vice President and Chief Accounting Officer of Sanchez Energy since January 2015, and she previously served as Sanchez Energy's Vice President and Principal Accounting Officer from March 2012. Sanchez Energy filed the Sanchez Energy Chapter 11 Case in August 2019. Mrs. Hink has served as Senior Vice President – Chief Accounting Officer of SOG since March 2016. Prior to joining Sanchez Energy, Mrs. Hink served as Controller of Vanguard Natural Resources, LLC from January 2011 to February 2012. From January 2010 to December 2010, she served as Assistant Controller of Mariner Energy, Inc. She served as the Chief Accounting Officer for Edge Petroleum Corporation, or Edge, from July 2008 through December 2009 and the Vice President and Controller for Edge from October 2003 through July 2008. Prior to that time, she served as Controller of Edge from December 31, 2000 to October 2003 and Assistant Controller of Edge from June 2000 to December 2000. Edge filed for bankruptcy in October 2009. Mrs. Hink is a Certified Public Accountant in the State of Texas.

Jack Howell was elected as a member of the Board in October 2015. Mr. Howell is a Senior Managing Director at Stonepeak and a member of Stonepeak's Executive Committee. Mr. Howell has been with Stonepeak since 2015. Prior to joining Stonepeak, Mr. Howell covered the oil and gas sector for Davidson Kempner, a hedge fund that focuses on distressed investments, from 2014 to 2015. Prior to Davidson Kempner, Mr. Howell worked for Denham Capital, an energy-focused private equity firm from 2011 to 2014. Mr. Howell started his career as an Analyst in Credit Suisse's oil and gas investment banking group. Mr. Howell holds a Bachelor of Arts degree in Plan II Honors and Business Economics, Phi Beta Kappa, from the University of Texas at Austin.

Richard S. Langdon was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in December 2006. Mr. Langdon is an independent member of the Audit Committee and the Conflicts Committee. Mr. Langdon is currently the Executive Vice President and Chief Financial Officer of Altamont Energy LLC, a privately held exploration and production company. Mr. Langdon previously served as the President and Chief Executive Officer of Badlands Energy, Inc., a privately held exploration and production company ("Badlands Energy"), and its publicly traded predecessor entity, Gasco Energy, Inc. ("Gasco"), from May 2013 to October 2018. Mr. Langdon also served as a director of Badlands Energy and its predecessor, Gasco since 2003. Badlands Energy filed for bankruptcy in August 2017. In addition to his Badlands Energy titles, Mr. Langdon also served as Debtor-in-Possession for Badlands Energy, Inc from August 2017 to October 2018. Mr. Langdon also currently serves on the board of directors, as chairman of the audit committee and as a member of the compensation committee of Gulfslope Energy, Inc., which capacities he has served in since March 2014. Mr. Langdon was the President and Chief Executive Officer of KMD Operating Company LLC ("KMD Operating"), a privately held production company, from November 2011 until December 2015 and Matris Exploration Company L.P., a privately held production company, from July 2004 until the merger of Matris Exploration into KMD Operating in November 2011, which merger was effective January 2011. Mr. Langdon also served as President and Chief Executive Officer of Sigma Energy Ventures, LLC, a privately held production company, from November 2007 until November 2013. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, he held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President—International Marketing—Pennzoil Products Company; Senior Vice President—Business Development—Pennzoil Company; and Senior Vice President—Commercial & Control—Pennzoil Exploration & Production Company.

G. M. Byrd Larberg was elected as a member of the Board in March 2015. He was previously a director of Sanchez Production Partners LLC, having been first elected in July 2014. Mr. Larberg is an independent member of the Audit Committee and is the Chair of the Conflicts Committee. Mr. Larberg served as a member of the board of directors of Horizon Energy, a private Exploration Company with both domestic and international focus, from 2017 to 2019. From 2010 to 2012, Mr. Larberg served as a member of the board of directors of Risco Resources, a small independent exploration company headquartered in Jakarta, Indonesia, which was sold in 2012. Mr. Larberg served as a member of the board of directors of 3GIG, an exploration-focused software firm headquartered in Houston, Texas, from 2008 to 2013 and now serves as an advisor to the board. He is active on the board of directors of the Houston Metropolitan YMCA and was previously chairman of the board. He was a member of the board of directors of Meridian Resources, a Houston-based exploration company, from 2007 until it was acquired by Alta Mesa in 2010. Mr. Larberg began his career at Shell Exploration and Production Company as a geologist in 1976. Over the next 21 years, he held various leadership positions within various Shell entities, and served as Vice President of Exploration and Production, Africa and Latin America for Pecten International, an affiliate of Shell Oil Company, from 1993 to 1996. Mr. Larberg left Shell and joined Burlington

Resources in 1998. From 1998 to 2006, Mr. Larberg held several key positions at Burlington Resources, beginning as Vice President of Exploration for Burlington Resources International. In 2000, Mr. Larberg was elected Executive Vice President and Chief Operating Officer of Burlington Resources International, a position he held until 2003, when he moved to the corporate office as Vice President of Geosciences. In this capacity, he was responsible for technical excellence for the geology and geophysical ("G&G") programs across the company, G&G technology business development, and management of the company-wide exploration portfolio. Mr. Larberg retired from Burlington Resources in April 2006 following the company's purchase by ConocoPhillips. Mr. Larberg was a director of Duma Hydrocarb Energy Corporation, a publicly traded production company, for a brief period in 2014. He occasionally consults in the areas of technical and portfolio management for exploration companies, and has provided such consulting services to a number of companies including Pemex, Maersk, ONGC, Ecopetrol, Repsol, HOCOL and the Kuwait National Petroleum Company.

Antonio R. Sanchez, III was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in August 2013. Mr. Sanchez, III is Chairman of the Board. He currently serves as the President & Chief Executive Officer of Sanchez Energy and has been a member of Sanchez Energy's board of directors since its formation in August 2011. Sanchez Energy filed the Sanchez Energy Chapter 11 Case in August 2019. He has been directly involved in the oil and gas industry for over 13 years. Mr. Sanchez, III is also the Co-President of SOG, which he joined in October 2001. He was the President of SEP Management I, LLC and was a Managing Director of Sanchez Energy Partners I, LP until their dissolution in December 2016. In his capacities as a director and officer of these companies, Mr. Sanchez, III has managed all aspects of their daily operations, including exploration, production, finance, capital markets activities, engineering and land management. From 1997 to 1999, Mr. Sanchez, III was an investment banker specializing in mergers and acquisitions with J.P. Morgan Securities Inc. From 1999 to 2001, Mr. Sanchez, III worked in a variety of positions, including sales and marketing, product development and investor relations, at Zix Corporation, a publicly traded encryption technology company (NASDAQ: ZIXI). Mr. Sanchez, III was also a member of the board of directors of Zix Corporation from May 2003 to June 2014.

Eduardo A. Sanchez was elected as a member of the Board in June 2015. Mr. Sanchez served as president of Sanchez Energy from October 2015 to November 2017, President and Chief Executive Officer of Sanchez Resources, LLC from February 2010 until November 2017, co-president of SOG from July 2014 to November 2017, and chief executive officer of Sanchez Oil & Gas Mexico Holdings, LLC from August 2015 to December 2017. Sanchez Energy filed the Sanchez Energy Chapter 11 Case in August 2019. Prior to his work at Sanchez Resources, LLC, Mr. Sanchez worked at Commonwealth Associates, Inc. focusing on private equity and debt placements in small and midsize market capitalization businesses including those in the energy sector.

Patricio D. Sanchez was elected President & Chief Operating Officer of our general partner in March 2017, Chief Operating Officer of our general partner in May 2015 and as a member of the Board in June 2015. Mr. Sanchez has served as co-president of SOG since June 2014 and prior to that from April 2010 to June 2014 as an Executive Vice President. Mr. Sanchez has served as an Executive Vice President of Sanchez Energy since November 2016. Sanchez Energy filed the Sanchez Energy Chapter 11 Case in August 2019. Mr. Sanchez has also been the managing member of Santerra Holdings, LLC, an oil and gas production company, since February 2012. Mr. Sanchez has managed many aspects of these companies' daily operations, including exploration, production, finance, capital markets activities, engineering and land management.

Luke R. Taylor was elected as a member of the Board in October 2015. Mr. Taylor has served as a Senior Managing Director with Stonepeak since August 2011 and serves as a member of Stonepeak's Executive Committee. Mr. Taylor has been investing across the infrastructure space for over 15 years and sits on the boards of Lineage Logistics, Golar Power and Ironclad Energy Partners, and is a former director of Paradigm Energy Partners, Tidewater Holdings, Carlsbad Desalination Project, Casper Crude to Rail and Northstar Renewable Power. Prior to joining Stonepeak, Mr. Taylor was a Senior Vice President with Macquarie Capital based in New York. Mr. Taylor has a Bachelor of Commerce and a Master of Business (Distinction) from the University of Otago (New Zealand).

Charles C. Ward was elected Chief Financial Officer & Secretary of our general partner in March 2015. He previously served as Chief Financial Officer and Treasurer of Sanchez Production Partners LLC from March 2008 until its conversion to a limited partnership in March 2015 and Secretary from July 2014 until March 2015. Mr. Ward also served as a Vice President of Constellation Energy Commodities Group, Inc. from November 2005 until December 2008. Prior to that time, he was a Vice President of Enron Creditors Recovery Corp. from March 2002 to November 2005.

Gerald F. Willinger was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in August 2013. Mr. Willinger was elected Interim Chief Executive Officer of our general partner in April 2015 and Chief Executive Officer in December 2015. Mr. Willinger has served as a Managing Director of Sanchez Capital Advisors, LLC since February 2010 and as Executive Vice President of SOG since 2014. Mr. Willinger was also a co-founder, officer and director of Sanchez Resources from February 2010 to November 2017 when Sanchez Resources was acquired by Sanchez Energy Corporation. From 1998 to 2000, Mr. Willinger was an investment banker with Goldman, Sachs & Co. Mr. Willinger served in various private equity investment management roles at MidOcean Partners, LLC and its predecessor entity, DB Capital Partners, LLC, from 2000 to 2003 and at the Cypress Group, LLC from 2003 to 2006. Prior to joining Sanchez Capital Advisors, LLC, Mr. Willinger was a Senior Analyst for Silver Point Capital, LLC, a credit-opportunity fund, from 2006 to 2009.

Messrs. Howell and Taylor were elected as members of the Board in October 2015 pursuant a Board Representation and Standstill Agreement, by and among us, our general partner and Stonepeak Catarina, which was subsequently amended and restated by that certain Amended and Restated Board Representation and Standstill Agreement, dated as of August 2, 2019, by and among us, our general partner and Stonepeak Catarina (as amended and restated, the "Representation and Standstill Agreement"). Pursuant to the Representation and Standstill Agreement, we and our general partner agreed to permit Stonepeak Catarina to designate two persons to serve on the Board. The right to designate one Board member will immediately terminate on such date as Stonepeak Catarina no longer owns at least 25% of the Partnership's outstanding Class C Preferred Units issued to it; and the right to designate the second Board member will immediately terminate on such date as Stonepeak Catarina does not hold any issued and outstanding Class C Preferred Units. Stonepeak Catarina also has the right to appoint the three independent members to the Board if all of the Class C Preferred Units have not been redeemed by December 31, 2021, with such right continuing until all Class C Preferred Units have been redeemed.

Messrs. Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez are brothers.

Qualifications of the Board of Directors

The sole member of our general partner elects all of the members of the Board, except for two members designated by Stonepeak Catarina pursuant to the Representation and Standstill Agreement. The following sets forth the specific experience, qualifications, attributes and skills that led the sole member of our general partner to conclude that the persons appointed by it should serve as directors:

Mr. Bigman brings considerable financial, managerial, transaction and corporate governance experience to the Board. During his career, he has held management positions of increasing responsibility in major energy corporations throughout the world where he has successfully lead financings, financial restructurings, mergers and acquisitions involving companies focused on various aspects of the hydrocarbon value chain. With respect to energy finance, as Vice President and Director of Corporate Finance for TNK, a leading Russian oil and gas producer, he raised capital to finance the growth of the company from its privatization in 1997 through a sale of a 50% stake to British Petroleum (BP) in 2003, creating TNK-BP, a $20 billion joint venture. In the area of corporate governance, Mr. Bigman served on the board of directors of Basell Polyolefins, where he was a member of the audit and compensation committees, which is beneficial for our board operations. He has also served on several international boards, including the board of Svyazinvest, Russia's largest telecommunications holding company, and JKX Oil and Gas, a UK public company focused on international oil and gas assets.

Mr. Langdon brings considerable financial and managerial experience in the energy industry to the Board as well as his entrepreneurial abilities, all of which are valuable to the Board. He has served as the Chief Financial Officer of EEX Corporation, a publicly traded production company that merged with Newfield Exploration. He has also held significant commercial positions with the Pennzoil Companies, including roles in business development and marketing. He was also the founder and owner of two privately held oil and gas companies. Mr. Langdon has extensive experience in finance and accounting that adds significant value to the board's oversight role of our financial reporting. He has prior public company board and audit committee experience, which is beneficial for our board operations, and served as the chairman of the audit committee of Gasco until he was named Gasco's President and Chief Executive Officer.

Mr. Larberg brings significant technical, operational and financial management experience in the oil and natural gas industry to the Board. His background provides a unique perspective on the dynamics of the oil and natural gas production industry. He has considerable governance experience, having previously served on the boards of several other companies. Taken together, this wealth of experience is invaluable to our board.

Mr. Sanchez, III brings substantial oil and gas/energy industry experience in both public and private entities to the Board. In his current capacity as President & Chief Executive Officer of Sanchez Energy and as a member of the board of directors of Sanchez Energy, he brings the perspective of leading a publicly-traded upstream company. In his current capacity as Co-President of SOG, he brings particular expertise in operating multiple oil and natural gas entities through a shared service model.

Mr. Eduardo Sanchez brings substantial oil and gas/energy industry experience in both public and private entities to the Board. Through his past experience as the President of Sanchez Energy and co-president of SOG, he brings the perspective of leading a publicly-traded upstream company and particular expertise in operating multiple oil and natural gas entities through a shared service model.

Mr. Patricio Sanchez brings substantial oil and gas/energy industry experience in both public and private entities to the Board. As an Executive Vice President at Sanchez Energy, he brings the perspective of leading a publicly-traded upstream company. In his current capacity as Co-President of SOG, he brings particular expertise in operating multiple oil and gas entities through a shared service model.

Mr. Willinger brings substantial experience in risk management, finance and negotiated transactions in the energy industry to the Board. He has a valuable perspective on master limited partnerships, which provides the Board with unique insights into master limited partnership management and growth opportunities. In addition, he brings an expansive network of both private and public capital providers, which is useful for the Board when evaluating possible capital sources.

The following sets forth the specific experience, qualifications, attributes and skills that led the holders of our Class C Preferred Units to conclude that the persons appointed by them should serve as directors:

Mr. Howell brings extensive oil and gas investing experience, along with experience in oil and gas transaction financings and mergers and acquisitions to the Board.

Mr. Taylor brings significant investment experience in energy and infrastructure companies, along with experience in finance and mergers and acquisitions to the Board.

Committees of the Board of Directors

The Board has two standing committees: the Audit Committee and the Conflicts Committee. We do not have a compensation committee, but rather the Board approves executive officer salary changes and bonuses and equity grants to directors, executive officers, employees and service providers.

Audit Committee

As described in its charter, the Audit Committee is directly responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants to audit our financial statements, including assessing the independent auditor’s qualifications and independence, and establishes the scope of, and oversees, the annual audit. The Audit Committee also approves any other services provided by public accounting firms. The Board has delegated to the Audit Committee the review and approval of our decision to enter into derivative transactions and our exemption from the swap clearing and swap execution requirements of the Dodd-Frank Act. The Audit Committee provides assistance to the Board in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor’s qualifications and independence and the performance of our internal audit function. The Audit Committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and the Board established. In doing so, it is the responsibility of the Audit Committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and our management.

Messrs. Bigman (Chair), Langdon and Larberg are members of the Audit Committee. The Board has determined that Mr. Bigman is an "audit committee financial expert" as that term is defined in the applicable rules of the SEC and that he is "independent" as defined in applicable NYSE American listing standards.

Conflicts Committee

The Board has appointed a standing Conflicts Committee composed of the independent directors, Messrs. Larberg, (Chair), Bigman and Langdon, to review specific matters that the Board believes may involve conflicts of interest. The Conflicts Committee will review and evaluate the proposal, negotiate as the Conflicts Committee deems appropriate the terms of the proposal and determine if the resolution of a conflict of interest is fair and reasonable to us. If the Conflicts Committee approves a conflict of interest proposal, the proposal is then recommended to the entire Board. The members of the Conflicts Committee may not be security holders, officers or employees of our general partner, directors, officers, or employees of affiliates of the general partner or holders of any ownership interest in us other than common units or other publicly traded units and must meet the independence standards established by the NYSE American, the Exchange Act and other federal securities laws. If any resolution or course of action by our general partner or its affiliates with respect to a conflict of interest is approved by the Conflicts Committee, then such resolution or course of action shall be permitted and deemed approved by all of our partners, and shall not constitute a breach of our partnership agreement, or of any duty stated or implied by law or equity.

Other

We maintain on our website, http://www.sanchezmidstream.com, a copy of the Audit Committee charter as well as copies of the Corporate Governance Guidelines and Code of Business Conduct and Ethics that are applicable to us and our general partner. Copies of these documents are also available in print and may be obtained without charge, upon written request, by emailing our investor relations group at ir@sanchezmidstream.com. Our Code of Business Conduct and Ethics applies to our general partner's principal executive officer, principal financial officer and principal accounting officer, among others. We intend to post any changes to or waivers of our Code of Business Conduct and Ethics for the executive officers of our general partner on our website.

Certifications

The NYSE American requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by a listed company of the NYSE American's corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE American, we last provided such a certification on March 18, 2019. The certifications of the Chief Executive Officer and Chief Financial Officer of our general partners required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this Form 10-K.

Item 11. Executive Compensation

Our general partner has the sole responsibility for conducting our business and for managing our operations, and its Board makes decisions on our behalf. The executive officers of our general partner are employed by SOG and manage the day-to-day affairs of our business.

Summary Compensation Table

The following table sets forth the compensation of our named executive officers (which are the chief executive officer and the two next most highly compensated officers of our general partner) for 2019 and 2018:

Name and Principal Position	Year	Salary (a)	Cash Bonus (b)	Unit Awards (c)	All Other Compensation (d)	Total
Gerald F. Willinger	2019	$600,000	$750,000	$1,502,953	$ 60,229	$ 2,913,182
Chief Executive Officer (e)	2018	$600,000	$750,000	$1,799,980	$ 128,994	$ 3,278,974
Patricio D. Sanchez	2019	$400,000	$ —	$ —	$ 19,273	$ 419,273
President & Chief Operating Officer (e)	2018	$400,000	$ —	$1,299,989	$ 52,043	$ 1,752,032
Charles C. Ward	2019	$375,000	$350,000	$ 635,864	$ 45,367	$ 1,406,231
Chief Financial Officer and Secretary (e)	2018	$275,000	$350,000	$ 849,995	$ 40,476	$ 1,515,471

(a) On January 30, 2019, the Board increased Mr. Ward's base salary from $275,000 to $375,000 effective as of January 1, 2019.
(b) On August 2, 2019, the Board approved the Partnership's entry into Executive Agreements (defined below) with each of Messrs. Willing and Ward. The Executive Agreements contain annual cash bonuses ranges for each of Messrs. Willinger and Ward and also stipulate that, for the 2019 annual cash bonus, 50% of such bonuses were required to be paid no later than September 30, 2019 with the remainder to be paid no later than March 31, 2020. Pursuant to this requirement in the Executive Agreements, Messrs. Willinger and Ward were paid cash bonuses of $375,000 and $175,000 respectively, on September 30, 2019, as part of their 2019 annual cash bonus. Pursuant to the Executive Agreements (as defined below), we will pay Messrs. Ward and Willinger the remaining 50% of their 2019 annual cash bonuses on or before March 31, 2020.
(c) The amounts reported in this column reflect the aggregate grant date fair value of awards granted, if any, under our Plan for fiscal years 2019 and 2018, computed in accordance with FASB ASC Topic 718, excluding estimated forfeitures. See Note 15 "Unit-Based Compensation," to the Consolidated Financial Statements included under "Part II, Item 8. Financial Statements and Supplementary Data" for additional detail regarding these figures. On March 4, 2019, the Board awarded Messrs. Willinger and Ward long-term incentive awards, which were paid in the form of restricted units under the Plan that vest in equal installments over three years.
(d) The amount in this column reflects the amount of matching contributions made under our 401k plan; parking cost paid for our executive officers; the cost of life insurance, accidental death and dismemberment insurance, and health insurance for our executive officers; and for those executive officers who also serve as directors, this column includes cash fees they received for service as a director.
(e) Our named executive officers are eligible to participate in benefit plans such as medical, dental, vision, life and disability insurance, 401k and flexible spending accounts on the same terms as all employees or service providers.

Executive Agreements

On August 2, 2019, our general partner entered into Executive Services Agreements with each of Messrs. Willinger and Ward (each, an "Executive Agreement" and, collectively, the "Executive Agreements"). The Executive Agreements were approved by the Board on August 2, 2019. Each respective Executive Agreement provides (i) that the applicable executive will continue to serve in his current executive officer position with our general partner and provide services to us and our general partner during the applicable term, (ii) for an annual base salary (Mr. Willinger: $600,000 and Mr. Ward: $375,000), (iii) for an annual cash bonus equal to a percentage of the annual base salary (Mr. Willinger: 100%-150% and Mr. Ward: 75%-125%) based on a qualitative assessment of financial and individual performance achievements, and (iv) for eligibility to receive awards under our Plan or any successor thereto and to participate in any long-term incentive programs available generally to the executive officers of our general partner, as determined in the sole discretion of the Board. Under each Executive Agreement, in the event of the applicable executive's termination as an officer of the general partner due to (a) such executive's death or "disability," (b) the general partner terminating such executive without "cause," or (c) such executive terminating for "good reason" (as such terms are defined in the Executive Agreements), such executive (or such executive's designated beneficiaries, as applicable) will be entitled to receive payment of: (i) any accrued but unpaid then-current annual base salary through the date of termination, (ii) any unpaid annual bonus for the year prior to the year of termination and (iii) a pro-rated annual bonus for the year of termination. In addition, such executive will also be entitled to receive the following severance payments or benefits in the event of: (1) the general partner terminating such executive without "cause" (2) such executive terminating for "good reason" or (3)(A) the general partner terminating such executive without "cause," (B) such executive's death or "disability," or (C) such executive terminating for any reason, in the case of (A)-(C), during a period beginning 60 days prior to and ending two years following a Change in Control (as defined in the Executive Agreements) such executive will be entitled to receive (w) a lump-sum cash payment equal to two times such executive's then-current annual base salary plus two times the largest annual bonus paid (or due to be paid) to such executive for the year in which the termination occurs or any year in the three calendar year period immediately preceding the date of termination, (x) payment of the COBRA premiums for such executive and such executive's eligible dependents during the COBRA continuation period, (y) to the extent not yet paid to such executive, a lump-sum cash payment equal to all outstanding amounts owed to such executive for services performed for or on behalf of us and our general partner, the amount of such executive's annual bonus for the last full year during which such executive performed services for us and our general partner, and the amount of such executive's annual bonus for the current year, based on such executive's annual bonus for such last full year (pro-rated to the date of termination), and (z) immediate vesting in full, as of the date of such Change in Control, of any units awarded to such executive under our Plan.

Outstanding Equity Awards at Fiscal Year-End 2019

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units on NYSE American at December 31, 2019 for the named executive officers:

Name	Number of Units Not Vested	Fair Market Value of Units Not Vested[(a)]
Gerald F. Willinger	576,185 [(b)]	$ 172,856
Patricio D. Sanchez	—	$ —
Charles C. Ward	248,665 [(b)]	$ 74,600

(a) Amounts are based on the closing price of our common units of $0.30 as reported on the NYSE American on December 31, 2019.
(b) Reflects restricted units granted under the Plan on April 6, 2018, which units either vest on the first anniversary of the grant date or vest pro-rata over a three-year period and on their first anniversary, respectively, as well as units granted under the Plan on March 4, 2019, which units vest pro-rata over a three year period. See footnote (c) to the Summary Compensation Table for additional information on the vesting schedule for these units. Except in connection with a change in control (as defined in the Plan) or in the discretion of the board of directors of our general partner, any unvested restricted units will be forfeited upon such time as the holder is no longer an officer, employee, consultant or director of us, our general partner, any of their affiliates or any other person performing bona fide services for us.

Compensation of Directors

For the year ended December 31, 2019, compensation for the independent directors of the Board consisted of:

- a cash retainer of $10,000, payable quarterly on the last day of each fiscal quarter;
- an equity grant of $100,000 of fully vested common units on March 31 of each year;
- a $1,500 fee for each meeting of the Board and $1,000 for each substantive meeting of the Audit Committee and $3,500 for each substantive meeting of the Conflicts Committee attended by a member thereof;
- a cash retainer of $3,500 for the Chair of the Audit Committee and $2,500 for the Chair of the Conflicts Committee, each payable quarterly on the last day of each fiscal quarter; and
- eligibility for independent directors to participate in health benefits generally available to all employees and reimbursement for up to $500,000 of life and accidental death and dismemberment insurance.

Directors designated by Stonepeak, officers of our general partner and any director with ownership interests in SP Holdings, LLC, were not eligible for the 2019 director compensation program outlined above. However, on January 30, 2019, the Board approved a long-term incentive award for Mr. A. Sanchez, which was paid in the form of 210,970 restricted units under the Plan that vest in equal installments over three years.

The following table sets forth a summary of the 2019 compensation for the directors except for Messrs. Willinger and P. Sanchez whose director compensation is included above under "—Summary Compensation Table":

	Director Compensation			
Name	Fees Earned or Paid in Cash	Unit Awards (a)	All Other Compensation (b)	Total
Alan S. Bigman	$ 69,500	$ 99,990	$ 21,155	$ 190,645
Jack Howell (c)	$ —	$ —	$ —	$ —
Richard S. Langdon	$ 55,500	$ 99,990	$ 1,020	$ 156,510
G. M. Byrd Larberg	$ 62,000	$ 99,990	$ 15,681	$ 177,671
Antonio R. Sanchez, III (d)	$ —	$ 578,058	$ —	$ 578,058
Eduardo A. Sanchez (d)	$ —	$ —	$ —	$ —
Luke R. Taylor (c)	$ —	$ —	$ —	$ —

(a) The amounts shown in this column for Messrs. Bigman, Langdon and Larberg represent the aggregate grant date fair value of the units granted under the Plan to Messrs. Bigman, Langdon and Larberg, computed in accordance with FASB ASC Topic 718, based on the $2.18 closing price per common unit on April 1, 2019. The amount shown in this column for Mr. A. Sanchez represents the aggregate grant date fair value of the units granted under the Plan to Mr. A. Sanchez, computed in accordance with FASB ASC Topic 718, based on the $2.74 closing price per common unit on March 4, 2019.

(b) All other compensation includes amounts for health, vision, dental, basic life and/or accidental death and dismemberment insurance premium fees paid by us for the director.

(c) As appointees of the holders of the Class C Preferred Units, Messrs. Howell and Taylor were not entitled to any compensation under our 2019 Board compensation program.

(d) As individuals with ownership interests in SP Holdings, Mr. A. Sanchez and Mr. E. Sanchez and Mr. P. Sanchez where not entitled to any compensation under our 2019 board compensation program, however, as noted above, Mr. A. Sanchez was awarded restricted units by the Board outside of the 2019 Board compensation program.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth the beneficial ownership of our units, as of March 13, 2020, held by:

- each unitholder known by us to beneficially own more than 5% of our outstanding units;
- each of the directors of the Board;
- each of our general partner's named executive officers (as such term is defined by the SEC); and
- the directors and executive officers of our general partner as a group.

The list of persons named in the table below is derived from our review of Form 3, Form 4, Form 5, Schedule 13D and Schedule 13G filings made with the SEC as of March 13, 2020. The amounts and percentage of common units and Class C Preferred Units beneficially owned are reported on the basis of the SEC rules governing the determination of beneficial ownership of securities. Under the SEC rules, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, and/or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities, and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Percentage of total units beneficially owned is based on 19,975,193 common units and 34,297,357 Class C Preferred Units outstanding as of March 13, 2020, the number of common units beneficially owned and the number of Class C Preferred Units beneficially owned is based upon ownership as of March 13, 2020, unless otherwise specified. Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

	Common Units Beneficially Owned		Class C Preferred Units Beneficially Owned		Percentage of Total Units Beneficially
Name and address of Beneficial Owner[(1)]	Number	Percentage	Number	Percentage	Owned
Stonepeak Catarina Holdings, LLC[(2)]	2,312,100	10.6 %	34,297,357	100 %	65.2 %
SN UR Holdings, LLC[(3)]	2,272,727	11.4 %	—	—	4.2 %
Invesco. Ltd[(4)]	1,758,705	8.8 %	—	—	3.2 %
Alan S. Bigman[(5)]	77,254	*	—	—	*
Kirsten A. Hink	23,933	*	—	—	*
Jack Howell	—	—	—	—	—
Richard S. Langdon	81,827	*	—	—	*
G. M. Byrd Larberg	76,096	*	—	—	*
Antonio R. Sanchez, III[(6)]	1,337,508	6.7 %	—	—	2.5 %
Eduardo A. Sanchez	1,141,846	5.7 %	—	—	2.1 %
Patricio D. Sanchez	1,291,574	6.4 %	—	—	2.4 %
Luke R. Taylor	—	—	—	—	—
Charles C. Ward	381,048	1.9 %	—	—	*
Gerald F. Willinger	1,104,614	5.5 %	—	—	2.0 %
All directors and executive officers as a group (11 persons)	5,515,700	27.6 %	—	—	10.2 %

* Less than 1%

(1) Unless otherwise set forth below, the address of all beneficial owners is c/o Sanchez Midstream Partners LP, 1000 Main Street, Suite 3000, Houston, Texas 77002.

(2) Ownership data as reported (i) on Schedule 13D/A filed on August 6, 2019 by Stonepeak Catarina Holdings LLC, Stonepeak Catarina Upper Holdings LLC, Stonepeak Infrastructure Fund (Orion AIV) LP, Stonepeak Associates LLC, Stonepeak GP Holdings LP, Stonepeak GP Investors LLC, Stonepeak GP Investors Manager LLC, Michael Dorrell and Trent Vichie (the "Stonepeak Beneficial Owners"), and (ii) publicly disclosed information regarding distributions of Class C Preferred PIK Units issued to Stonepeak Catarina Holdings LLC following the effective date of the Exchange, consisting of 939,327 Class C Preferred PIK Units issued on August 30, 2019, 1,007,820 Class C Preferred PIK Units issued on November 29, 2019 and 1,039,314 Class C Preferred PIK Units issued on February 28, 2020. The number of common units disclosed in the Schedule 13D/A includes 1,918,809 common units that the Stonepeak Beneficial Owners currently have the right to acquire within the next 60 days upon exercise of a Warrant held by Stonepeak Catarina Holdings LLC, such common units are not included for any other person on this table in accordance with Rule 13d-3(d)(1)(i) under the Exchange Act. The principal business address of each reporting person in the Schedule 13D/A is 55 Hudson Yards, 550 W. 34th St., 48th Floor, New York, NY 10001. The Schedule 13D/A filing lists each filing person as having shared voting and dispositive power over the common units and the Class C Preferred Units.

(3) Ownership data as reported on Schedule 13D filed on November 28, 2016 by SN UR Holdings, LLC and Sanchez Energy Corporation. The principal business address of each filing reporting person is 1000 Main Street, Suite 3000, Houston, Texas 77002. The filing lists each filing person as having shared voting and dispositive power over the common units.

(4) Ownership data as reported on a Schedule 13G filing dated February 13, 2020 by Invesco Ltd. The principle business address of the reporting person is 1555 Peachtree Street NE, Suite 1800, Atlanta, GA 30309. The filing lists the reporting person as having sole voting and dispositive power over the common units.

(5) Of these common units, 1,000 are held by Mr. Bigman's minor children.

(6) Of these common units, 35,320 are owned directly by SOG. SOG is managed by Mr. Sanchez and other members of the Sanchez family. Mr. Sanchez shares voting and dispositive power over the securities controlled by SOG. Mr. Sanchez disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information for our only equity compensation plan, the Sanchez Midstream Partners LP Long-Term Inventive Plan (the "Plan"), as of December 31, 2019:

Plan Category	Number of Securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	—	$ —	840,811
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	840,811

Item 13. Certain Relationships and Related Transactions, and Director Independence

Manager

We are controlled by our general partner, Sanchez Midstream Partners GP LLC. The sole member of our general partner is Manager, which has no officers. The sole manager and member of Manager is SP Capital Holdings, LLC, which has no officers. The co-managers of SP Capital Holdings, LLC are Antonio R. Sanchez, III, a member of the Board and the Chairman of the Board; Eduardo A. Sanchez, a member of the Board; Patricio D. Sanchez, a member of the Board and the President and Chief Operation Officer of our general partner; and their father, Antonio R. Sanchez, Jr. SP Capital Holdings, LLC is owned by Antonio R. Sanchez, III (26%), Eduardo A. Sanchez (26%), and Patricio D. Sanchez (26%), along with their sister, Ana Lee Sanchez Jacobs (18%), and their father, Antonio R. Sanchez, Jr (4%).

In connection with providing the services under the Services Agreement, Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Prior to August 2, 2019 each of these fees, not including the reimbursement of costs, was paid in cash unless Manager elected for such fee to be paid in our equity. However, on August 2, 2019, we and Manager entered into a letter agreement providing that until such time as we redeem all of our issued and outstanding Class C Preferred Units, Manager will elect to receive its fees, not including reimbursement of costs, in common units rather than cash. In addition, on November 8, 2019, we and Manager entered into an additional letter agreement 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 (the "Tolling Period"), Manager agrees to delay receipt of its fees, not including reimbursement of costs. During the Tolling Period, we are required to keep an accurate ledger of the dollar amount of the fee applicable to each quarter within the Tolling Period and the daily closing price of our common units on the NYSE. Following the end of the Tolling Period we will provide a notice to Manager including such ledgers and pay the accrued fees within thirty days of delivery of such notice. The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless we or Manager provide notice of termination to the other with at least 180 days' notice. For the fees earned during the three months ended March 31, 2019 and June 30, 2019, Manager elected to receive 1,789,010 common units equal to approximately $3.9 million, in lieu of cash. For the fees earned during the three months ended September 30, 2019 and December 31, 2019, pursuant to the November 8, 2019 letter agreement, Manager did not receive any fees, other than reimbursement of its costs. However, pursuant to the requirements under the November 8, 2019 letter agreement, we have determined that the fees earned during the three months ended September 30, 2019 and December 31, 2019, are approximately $1.9, and $1.5 million, respectively. During the years ended December 31, 2019 and 2018, we incurred costs of approximately $7.3 million and $8.6 million, respectively, to Manager under the Services Agreement.

SOG

SOG provides services to us through a contractual relationship with SP Holdings. Antonio R. Sanchez, III and Patricio D. Sanchez are Co-Presidents of SOG; Antonio R. Sanchez, Jr. is the Chief Executive Officer and sole director of SOG; Ana Lee Sanchez Jacobs is an Executive Vice President of SOG; and Gerald F. Willinger is an Executive Vice President of SOG. The controlling owners of SOG are Antonio R. Sanchez, Jr. and Santig, Ltd. The general partner of Santig, Ltd. is Sanchez Management Corporation, which is owned 100% by Antonio R. Sanchez, Jr. Antonio R. Sanchez, Jr. is Chairman and President of Sanchez Management Corporation and Antonio R. Sanchez, III is Executive Vice President of Sanchez Management Corporation. For the years ended December 31, 2019 and 2018, SOG received $0.2 million and $0.3 million, respectively, as a result of its Services Agreement with SP Holdings.

Sanchez Energy

Since January 1, 2015, we have completed three midstream acquisitions and two working interest acquisitions from Sanchez Energy. Antonio R. Sanchez, Jr., the father of Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez, is a director and Executive Chairman of the board of directors of Sanchez Energy, Antonio R. Sanchez, III, is a director and President and Chief Executive Officer of Sanchez Energy, Eduardo A. Sanchez is the former President of Sanchez Energy and Patricio D. Sanchez is an Executive Vice President of Sanchez Energy. The employees of SOG, including Kirsten A. Hink, our Chief Accounting Officer, provide common services to both us and Sanchez Energy. The beneficial ownership of Sanchez Energy's common stock as of March 13, 2020 by Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez was 6.1%, 3.0%, 1.1% and 1.2%, respectively. As of March 13, 2020, Sanchez Energy indirectly, through one of its wholly owned subsidiaries, beneficially owned approximately 11.4% of the outstanding common units of SNMP.

We entered into the Gathering Agreement with Sanchez Energy in October 2015. For the years ended December 31, 2019 and 2018, Sanchez Energy paid us approximately $59.4 million and $57.9 million, respectively, pursuant to the terms of the Gathering Agreement. On June 30, 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by Sanchez Energy based on water that is delivered through the gathering system through March 31, 2018. Subsequent to the conclusion of the incremental infrastructure fee amendment, the parties have agreed to continue the incremental infrastructure fee on a month-to-month basis. On January 1, 2019 and April 1, 2019, the Partnership increased the Western Catarina Midstream tariff rate for throughput volumes that are outside of the dedicated acreage under the Gathering Agreement.

As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at Carnero Gathering's delivery points from Sanchez Energy and other producers. For the years ended December 31, 2019 and 2018, we made earnout payments to Sanchez Energy of $32.0 thousand and $64.0 thousand, respectively.

In September 2017, we entered into the Seco Pipeline Transportation Agreement. For the years ended December 31, 2019 and 2018, Sanchez Energy paid us approximately $6.8 million and $7.2 million, respectively, pursuant to the terms of such agreement. On January 13, 2020, we received written notice from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective February 12, 2020.

In May 2018, the Carnero JV, which is operated by Targa, received a dedication from Sanchez Energy and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Sanchez Energy's Comanche Asset pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the joint ventures limited by the capacity of the Raptor Gas Processing Facility.

Stonepeak

Class B Preferred Unit Issuance

In accordance with our partnership agreement, in December 2016, we issued an additional 9,851,996 Class B Preferred Units to Stonepeak. Stonepeak disagreed with our calculation of the additional Class B Preferred Units due under our partnership agreement and in January 2017, we and Stonepeak entered into a settlement agreement to settle the disputed calculation. Pursuant to the settlement agreement, and in accordance with Section 5.4 of our partnership agreement then in effect, we issued 1,704,446 Class B Preferred Units to Stonepeak in a privately negotiated transaction as consideration for the Settlement Agreement, with the “Class B Preferred Unit Price” under our partnership agreement being established at $11.29 per Class B Preferred Unit.

In July 2018, the Partnership elected to pay the second-quarter 2018 distribution on the Class B Preferred Units in part cash and part in Class B Preferred PIK Units. Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B Preferred Unit and an aggregate distribution of 310,009 Class B Preferred PIK Units, which was paid on August 31, 2018 to Stonepeak.

Class C Preferred Unit Issuance

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

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

On October 30, 2019, the Board declared that after establishing a cash reserve for the payment of certain amounts outstanding under the Credit Agreement, the Partnership did not have any available cash and, as a result, there would be no cash distribution on the Partnership’s common units. As required by the Amended Partnership Agreement, the Board declared a third quarter distribution on the Class C Preferred Units payable 100% in Class C Preferred PIK Units. Accordingly, the Partnership declared an aggregate distribution of 1,007,820 Class C Preferred PIK Units, paid on November 29, 2019 to holders of record on November 20, 2019.

Warrant

On August 2, 2019, in connection with the Exchange, Stonepeak Catarina received the Warrant. The Warrant may be exercised at any time and from time to time during the period beginning on August 2, 2019 and ending on the later of the seventh anniversary of such date and the date thirty days after the date on which all of the Class C Preferred Units have been redeemed for a number of Junior Securities (as such term is defined in the Warrant) equal to 10% of each applicable class of Junior Securities then outstanding as of the exercise date. No exercise price will be payable in connection with the exercise of the Warrant.

Item 14. Principal Accounting Fees and Services

We engaged our principal accountant, KPMG LLP ("KPMG"), to audit our financial statements and perform other professional services for the fiscal years ended December 31, 2019 and 2018.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ended December 31, 2019 and 2018 were $978,885 and $1,192,912, respectively.

Audit-Related Fees. There were no audit-related fees billed by KPMG for the years ended December 31, 2019 and 2018.

Tax Fees. There were no tax fees billed by KPMG for the years ended December 31, 2019 and 2018.

All Other Fees. There were no other fees billed by KPMG for the years ended December 31, 2019 and 2018.

Audit Committee Pre-Approval Policies and Practices

The Audit Committee must pre-approve any audit and permissible non-audit services performed by our independent registered public accounting firm. In addition, the Audit Committee has oversight responsibility to ensure that the independent registered public accounting firm is not engaged to perform certain enumerated non-audit services, including, but not limited to, bookkeeping, financial information system design and implementation, appraisal or valuation services, internal audit outsourcing services and legal services. The Audit Committee has adopted an audit and non-audit services pre-approval policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent registered public accounting firm must be approved. Pursuant to the policy, all services must be reviewed and approved and the chairman of the Audit Committee has been delegated the authority to specifically pre-approve services, which pre-approval is subsequently reviewed with the committee. All of the services described as Audit Fees, Audit-Related Fees, Tax Fees and All Other Fees were approved by the Audit Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this Form 10-K:

1. Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

2. Financial Statement Schedules:

None.

3. Exhibits Required by Item 601 of Regulation S-K.

The exhibits required by Item 601 of Regulation S-K are listed in subparagraph (b) below.

(b) The following exhibits are filed or furnished with this Form 10-K or incorporated by reference:

On June 2, 2017 we changed our name to Sanchez Midstream Partners LP from Sanchez Production Partners LP.

Exhibit Number	Description
2.1	Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K field by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 31, 2015, between SEP Holdings III, LLC, Sanchez Production Partners LP and SEP Holdings IV, LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 1, 2015, File No. 001-33147).
2.3	Purchase and Sale Agreement, dated as of September 25, 2015, by and among Sanchez Energy Corporation, SN Catarina, LLC and Sanchez Production Partners LP (incorporated herein by reference to Exhibit 2.1 the Current Report on Form 8-K filed by Sanchez Production Partners LP on September 29, 2015, File No. 001-33147).
2.4	Purchase and Sale Agreement by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP, dated July 5, 2016 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on August 12, 2016, File No. 001-33147).
2.5	Purchase and Sale Agreement, dated October 6, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 7, 2016, File No. 001-33147).

2.6	Purchase and Sale Agreement, dated October 6, 2016, by and among SN Cotulla Assets, LLC, SN Palmetto, LLC, SEP Holdings IV, LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 7, 2016, File No. 001-33147).
2.7	Purchase and Sale Agreement, dated October 6, 2016, by and among Sanchez Energy Corporation, SN Terminal, LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 7, 2016, File No. 001-33147).
2.8	Membership Interest Purchase and Sale Agreement, dated May 10, 2017, between Sanchez Midstream Partners LP (f/k/a Sanchez Production Partners LP) and Exponent Energy, LLC (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
2.9	Purchase and Sale Agreement, dated June 30, 2017, between SEP Holdings IV, LLC and Sendero Petroleum, LLC (incorporated by reference to Exhibit 2.2 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
2.10	Amendment No. 1 to Purchase and Sale Agreement, dated July 31, 2017, between SEP Holdings IV, LLC and Sendero Petroleum, LLC (incorporated by reference to Exhibit 2.3 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
2.11	Purchase and Sale Agreement between Sanchez Midstream Partners LP and Dallas Petroleum Group, LLC dated October 12, 2017 (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on November 14, 2017, File No. 001-33147).
2.12	Agreement to Purchase Oil and Gas Interests between SEP Holdings IV, LLC and EP Energy E&P Company, L.P., dated April 30, 2018 (incorporated herein by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on May 10, 2018, File No. 001-33147).
3.1	Certificate of Conversion of Sanchez Production Partners LLC (incorporated herein by reference to Exhibit 4.1 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
3.2	Certificate of Limited Partnership of Sanchez Production Partners LP (incorporated herein by reference to Exhibit 4.2 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
3.3	Certificate of Amendment to Certificate of Limited Partnership (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on June 2, 2017, File No. 001-33147).
3.4	Third Amended and Restated Agreement of Limited Partnership of Sanchez Production Partners LP (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
3.5	Certificate of Formation of Sanchez Production Partners GP LLC (incorporated by reference to Exhibit 4.4 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
3.6	Limited Liability Company Agreement of Sanchez Production Partners GP LLC (incorporated herein by reference to Exhibit 4.5 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).

3.7	Amendment No. 1 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC (incorporated herein by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q/A filed by Sanchez Production Partners LP on September 3, 2015, File No. 001-33147).
3.8	Amendment No. 2 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
3.9	Amendment No. 3 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC, dated August 2, 2019 (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on August 5, 2019, File No. 001-33147).
4.1	Registration Rights Agreement, dated November 22, 2016, between Sanchez Production Partners LP and SN UR Holdings, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on November 22, 2016, File No. 001-33147).
4.2	Amended and Restated Registration Rights Agreement, dated August 2, 2019, by and among Sanchez Midstream Partners LP and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
4.3*	Description of Registrant Securities.
10.1	Purchase Agreement, dated November 16, 2016, between Sanchez Production Partners LP and SN UR Holdings, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on November 22, 2016, File No. 001-33147).
10.2	Third Amended and Restated Credit Agreement, dated as of March 31, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 1, 2015, File No. 001-33147).
10.3	Amendment and Waiver of Third Amended and Restated Credit Agreement, dated as of August 12, 2015, between Sanchez Production 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 Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on August 14, 2015, File No. 001-33147).
10.4	Joinder, Assignment and Second Amendment to Third Amended and Restated Credit Agreement, dated as of October 14, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
10.5	Third Amendment to Third Amended and Restated Credit Agreement, dated as of November 12, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on November 13, 2015, File No. 001-33147).

10.6	Fourth Amendment to Third Amended and Restated Credit Agreement among Sanchez Production Partners LP, the guarantors party thereto, each of the lenders party thereto, and Royal Bank of Canada, as administrative agent and collateral agent, dated July 5, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on August 12, 2016, File No. 001-33147).
10.7	Fifth Amendment to the Third Amended and Restated Credit Agreement dated as of April 17, 2017, between Sanchez Production Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on May 15, 2017, File No. 001-33147).
10.8	Sixth Amendment to the Third Amended and Restated Credit Agreement dated as of November 7, 2017, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on November 14, 2017, File No. 001-33147).
10.9	Seventh Amendment to the Third Amended and Restated Credit Agreement dated as of February 5, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.11 to the Annual Report on Form 10-K filed by Sanchez Midstream Partners LP on March 12, 2018, File No. 001-33147).
10.10	Eighth Amendment to the Third Amended and Restated Credit Agreement dated as of May 7, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on May 10, 2018, File No. 001-33147).
10.11	Ninth Amendment to the Third Amended and Restated Credit Agreement dated as of May 7, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on November 25, 2019, File No. 001-33147).
10.12*	Summary Compensation of Executive Officers of Sanchez Midstream Partners GP LLC.
10.13*	Summary Compensation of Directors of Sanchez Midstream Partners GP LLC.
10.14	Amended and Restated Shared Services Agreement, dated as of March 6, 2015, between SP Holdings, LLC and Sanchez Production Partners LP (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).
10.15	Contract Operating Agreement, dated May 8, 2014, between Constellation Energy Partners LLC and Sanchez Oil & Gas Corporation (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 8, 2014, File No. 001-33147).
10.16	Geophysical Seismic Data Use License Agreement, dated May 8, 2014, between Constellation Energy Partners, LLC, certain subsidiaries thereof, and Sanchez Oil & Gas Corporation (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 8, 2014, File No. 001-33147).

10.17	Amendment One to License Agreement, dated as of March 6, 2015, by and among Sanchez Oil and Gas Corporation, Sanchez Production Partners LP and SEP Holdings IV, LLC (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).
10.18	Firm Gathering and Processing Agreement, dated as of October 14, 2015, by and between Catarina Midstream, LLC and SN Catarina, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
10.19	Amendment No. 1 to Firm Gathering and Processing Agreement by and between SN Catarina, LLC and Catarina Midstream, LLC, dated June 30, 2017 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
10.20+	Sanchez Production Partners LP Long-Term Incentive Plan (incorporated herein by reference to Exhibit 4.6 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
10.21+	Form of Award Agreement Relating to Restricted Units (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on December 3, 2015, File No. 001-33147).
10.22+	Form of Award Agreement Relating to Restricted Units (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on March 28, 2017, File No. 001-33147).
10.23	Settlement Agreement and Release, effective January 25, 2017, by and between Stonepeak Catarina Holdings LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on January 27, 2017, File No. 001-33147).
10.24+	Form of Award Agreement Relating to Restricted Units incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Sanchez Midstream Partners LP on March 7, 2019, File No. 001-33147.
10.25	Amended and Restated Board Representation and Standstill Agreement, dated August 2, 2019, by and among Sanchez Midstream Partners LP, Sanchez Midstream Partners GP LLC and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
10.26+	Form of Executive Services Agreement (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners on August 8, 2019, File No. 001-33147).
10.27	Warrant Exercisable for Junior Securities, dated August 2, 2019, by and between Sanchez Midstream Partners LP and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
21.1*	List of subsidiaries of Sanchez Midstream Partners LP.

23.1*	Consent of KPMG LLP.
23.2*	Consent of Ryder Scott Co. LP.
31.1*	Certification of Chief Executive Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer and Secretary of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief 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 Chief Financial Officer and Secretary 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.
99.1*	Report of Ryder Scott Co. LP
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith
\+ Management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Sanchez Midstream Partners LP

By: Sanchez Midstream Partners GP LLC, its general partner

Date: March 13, 2020

By /s/ Gerald F. Willinger
Name **Gerald F. Willinger**
Title **Chief Executive Officer**

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below, constitutes and appoints Gerald F. Willinger and Charles C. Ward, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite or necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

This report has been signed below by the following persons on behalf of the general partner of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Antonio R. Sanchez, III **Antonio R. Sanchez, III**	Director; Chairman of the Board	March 13, 2020
/s/ Gerald F. Willinger **Gerald F. Willinger**	Director; Chief Executive Officer (Principal Executive Officer)	March 13, 2020
/s/ Charles C. Ward **Charles C. Ward**	Chief Financial Officer & Secretary (Principal Financial Officer)	March 13, 2020
/s/ Patricio D. Sanchez **Patricio D. Sanchez**	Director; President & Chief Operating Officer (Principal Operating Officer)	March 13, 2020
/s/ Kirsten A. Hink **Kirsten A. Hink**	Chief Accounting Officer (Principal Accounting Officer)	March 13, 2020
/s/ Alan S. Bigman **Alan S. Bigman**	Director	March 13, 2020
/s/ Jack Howell **Jack Howell**	Director	March 13, 2020
/s/ Richard S. Langdon **Richard S. Langdon**	Director	March 13, 2020
/s/ G. M. Byrd Larberg **G. M. Byrd Larberg**	Director	March 13, 2020
/s/ Eduardo A. Sanchez **Eduardo A. Sanchez**	Director	March 13, 2020
/s/ Luke R. Tayler **Luke R. Taylor**	Director	March 13, 2020

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Sanchez Midstream Partners LP and the Board of Directors of Sanchez Midstream Partners GP LLC
Sanchez Midstream Partners LP:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Sanchez Midstream Partners LP and subsidiaries (the Partnership) as of December 31, 2019 and 2018, the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/KPMG LLP

We have served as the Partnership's auditor since 2013.

Houston, Texas
March 13, 2020

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES
Consolidated Statements of Operations
(In thousands, except unit data)

	Years Ended December 31, 2019	Years Ended December 31, 2018
Revenues		
Natural gas sales	$ 683	$ 953
Oil sales	9,512	21,272
Natural gas liquid sales	539	1,709
Gathering and transportation sales	6,825	6,651
Gathering and transportation lease revenues	59,090	53,025
Total revenues	76,649	83,610
Expenses		
Operating expenses		
Lease operating expenses	7,378	7,864
Transportation operating expenses	11,553	12,316
Production taxes	621	1,104
General and administrative expenses	17,610	23,653
Unit-based compensation expense	1,351	1,938
Gain on sale of assets	—	(3,186)
Depreciation, depletion and amortization	25,333	25,987
Asset impairments	32,119	—
Accretion expense	526	497
Total operating expenses	96,491	70,173
Other (income) expense		
Interest expense, net	39,789	10,961
Earnings from equity investments	(2,831)	(12,859)
Other income	(5,860)	(546)
Total other (income) expenses	31,098	(2,444)
Total expenses	127,589	67,729
Income (loss) before income taxes	(50,940)	15,881
Income tax expense	202	190
Net income (loss)	(51,142)	15,691
Preferred unit paid-in-kind distributions	(14,409)	(3,500)
Preferred unit distributions	(8,838)	(33,425)
Preferred unit amortization	(1,708)	(2,358)
Deemed contribution	103,773	—
Net income (loss) attributable to common unitholders - Basic	27,676	(23,592)
Mark-to-market on Warrant	(3,244)	—
Net income (loss) attributable to common unitholders - Diluted	$ 24,432	$ (23,592)
Net income (loss) per unit		
Common units - Basic	$ 1.46	$ (1.55)
Common units - Diluted	$ 1.23	$ (1.55)
Weighted average units outstanding		
Common units - Basic	18,939,145	15,264,284
Common units - Diluted	19,810,679	15,264,284

See accompanying notes to consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES
Consolidated Balance Sheets
(In thousands, except unit data)

	December 31, 2019		December 31, 2018	
ASSETS				
Current assets				
Cash and cash equivalents	$	5,099	$	2,934
Accounts receivable		133		277
Accounts receivable - related entities		6,719		6,700
Prepaid expenses		1,193		931
Fair value of commodity derivative instruments		226		3,044
Total current assets		13,370		13,886
Oil and natural gas properties and related equipment				
Oil and natural gas properties, equipment and facilities (successful efforts method)		112,476		112,173
Gathering and transportation assets		186,941		186,406
Less: accumulated depreciation, depletion, amortization and impairment		(144,189)		(100,245)
Oil and natural gas properties and equipment, net		155,228		198,334
Other assets				
Intangible assets, net		145,246		158,706
Fair value of commodity derivative instruments		—		876
Equity investments		100,311		114,465
Other non-current assets		285		418
Total assets	$	414,440	$	486,685
LIABILITIES AND PARTNERS' CAPITAL				
Current liabilities				
Accounts payable and accrued liabilities	$	5,347	$	4,678
Accounts payable and accrued liabilities - related entities		631		5,641
Royalties payable		359		359
Short-term debt, net of debt issuance costs		39,374		—
Fair value of commodity derivative instruments		985		6
Other liabilities		—		125
Total current liabilities		46,696		10,809
Other liabilities				
Long term accrued liabilities - related entities		4,892		—
Asset retirement obligation		6,898		6,200
Long-term debt, net of debt issuance costs		109,437		178,582
Class C Preferred Units		281,688		—
Other liabilities		629		5,857
Total other liabilities		403,544		190,639
Total liabilities		450,240		201,448
Commitments and contingencies (See Note 13)				
Mezzanine equity				
Class B Preferred Units, zero and 31,310,896 units issued and outstanding as of December 31, 2019 and 2018, respectively		—		349,857
Partners' deficit				
Common units, 20,087,462 and 16,486,239 units issued and outstanding as of December 31, 2019 and 2018, respectively		(35,800)		(64,620)
Total partners' deficit		(35,800)		(64,620)
Total liabilities and partners' deficit	$	414,440	$	486,685

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31, 2019	Years Ended December 31, 2018
Cash flows from operating activities:		
Net income (loss)	$ (51,142)	$ 15,691
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation and depletion	11,873	12,527
Amortization of debt issuance costs	1,266	783
Accretion of Class C discount	13,129	—
Class C distribution accrual	19,309	—
Asset impairments	32,119	—
Accretion expense	526	497
Distributions from equity investments	17,227	24,946
Equity earnings in affiliate	(2,831)	(12,859)
Gain on sale of assets	—	(3,186)
Mark-to-market on Warrant	(3,244)	—
Net loss (gain) on commodity derivative contracts	3,772	(1,316)
Net cash settlements received (paid) on commodity derivative contracts	1,101	(1,326)
Unit-based compensation	1,351	1,938
Gain on earnout derivative	(5,856)	(546)
Amortization of intangible assets	13,460	13,460
Changes in Operating Assets and Liabilities:		
Accounts receivable	(6)	(377)
Accounts receivable - related entities	(23)	6,389
Prepaid expenses	(262)	1,739
Other assets	83	82
Accounts payable and accrued liabilities	6,378	13,719
Accounts payable and accrued liabilities- related entities	(122)	(5,333)
Royalties payable	—	(12)
Other long-term liabilities	(123)	126
Net cash provided by operating activities	57,985	66,942
Cash flows from investing activities:		
Development of oil and natural gas properties	(131)	(11)
Proceeds from sale of assets	—	7,692
Construction of gathering and transportation assets	(1,063)	(2,533)
Contributions to equity affiliates	(242)	(2,838)
Net cash provided by (used in) investing activities	(1,436)	2,310
Cash flows from financing activities:		
Payments for offering costs	—	(50)
Payments for Class C Preferred Unit Exchange	(238)	—
Proceeds from issuance of debt	4,000	2,000
Repayment of debt	(34,000)	(11,000)
Distributions to common unitholders	(5,216)	(23,243)
Class B Preferred Unit cash distributions	(17,675)	(33,338)
Units tendered by SOG employees for tax withholdings	(218)	—
Debt issuance costs	(1,037)	(1,008)
Net cash used in financing activities	(54,384)	(66,639)
Net increase in cash and cash equivalents	2,165	2,613
Cash and cash equivalents, beginning of period	2,934	321
Cash and cash equivalents, end of period	$ 5,099	$ 2,934
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 528	$ 525
Cash paid during the period for income taxes	$ 138	$ —
Cash paid during the period for interest	$ 9,159	$ 9,763

See accompanying notes to consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES
Consolidated Statements of Changes in Partners' Capital
(In thousands, except unit data)

	Common Units		Total
	Units	Amount	Capital
Partners' Deficit, December 31, 2017	14,965,134	$ (29,308)	$ (29,308)
Unit-based compensation programs	531,561	1,938	1,938
Issuance of common units, net of offering costs of $0.1 million	989,544	9,585	9,585
Cash distributions to common unit holders	—	(23,243)	(23,243)
Distributions - Class B Preferred Units	—	(39,283)	(39,283)
Net income	—	15,691	15,691
Partners' Deficit, December 31, 2018	16,486,239	$ (64,620)	$ (64,620)
Adoption of accounting standards	—	(181)	(181)
Preferred unit exchange	—	103,773	103,773
Unit-based compensation programs	1,109,880	1,531	1,531
Units tendered by SOG employees for tax withholdings	(85,417)	(218)	(218)
Common units issued for asset management fee	2,576,760	5,228	5,228
Cash distributions to common unitholders	—	(5,216)	(5,216)
Distributions - Class B Preferred Units	—	(24,955)	(24,955)
Net loss	—	(51,142)	(51,142)
Partners' Deficit, December 31, 2019	20,087,462	$ (35,800)	$ (35,800)

See accompanying notes to consolidated financial statements.

SANCHEZ MIDSTREAM PARTNERS LP AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2019 and 2018

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 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. On June 2, 2017, we changed our name to Sanchez Midstream Partners LP from Sanchez Production Partners LP. Manager owns our general partner and all of our incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol "SNMP."

2. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Accounting policies used by us conform to accounting principles generally accepted in the United States of America ("GAAP). 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, the Carnero JV and Seco Pipeline. Production consists of our oil and natural gas properties in Texas and Louisiana. Our management evaluates performance based on these two business segments.

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 August 2018, the FASB issued Accounting Standards Update ("ASU") 2018-13 "Fair Value Measurement (ASC 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements," which modifies the disclosure requirements on fair value measurements. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019. We do not anticipate the adoption of this standard to have a material impact on our consolidated financial statements.

In June 2018, the FASB issued ASU 2018-07 "Compensation - Stock Compensation (Topic 718) - Improvements to Nonemployee Share-Based Payment Accounting," which expands the scope of Topic 718, "Compensation – Stock Compensation", to include share-based payment transactions for acquiring goods and services from nonemployees. We adopted this ASU effective January 1, 2019, which resulted in the remeasurement of our outstanding unvested awards as of January 1, 2019 and changed the expense recorded for equity awards going forward. The adoption of this standard resulted in an approximately $0.2 million charge to retained earnings.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in more timely recognition of losses. 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 consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02 “Leases (Topic 842),” effective for annual and interim periods for public companies beginning after December 15, 2018. Additionally, in July 2018, the FASB issued ASU 2018-10, “Codification Improvements to Topic 842 (Leases),” which provides narrow amendments to clarify how to apply certain aspects of ASU 2016-02. The Partnership elected the practical expedients disclosed in ASU 2018-10. The effective date in ASU 2018-10 is the same as that of ASU 2016-02. The standards update the previous lease guidance by requiring the recognition of a right-of-use asset and lease liability on the statement of financial position for those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee’s classification of a finance lease. The Partnership adopted this standard effective January 1, 2019. The adoption of this standard did not have a material impact on our 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 consolidated financial statements are prepared in conformity with GAAP, which requires management to make estimates and assumptions that affect the amounts reported in the 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.

Revenue Recognition

Midstream

We account for revenue from contracts with customers in accordance with ASC 606 and ASC 842 for our midstream segment. The Seco Pipeline Transportation Agreement is our only contract that we account for using ASC 606. Under the Seco Pipeline Transportation Agreement, we agreed to provide transportation services of certain quantities of natural gas from the receipt point to the delivery point. Each MMBtu of natural gas transported is distinct and the transportation services performed on each distinct molecule of product is substantially the same in nature. As such, we applied the series guidance and treat these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. Additionally, Seco Pipeline Transportation Agreement contains variable consideration in the form of volume variability. As the distinct goods or services (rather than the series) are considered for the purpose of allocating variable consideration, we have taken the optional exception under ASC 606. Under this exception, 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.

The Gathering Agreement (as defined in Note 14 “Related Party Transactions”) was classified as an operating lease at inception and is accounted for under ASC 842, as Sanchez Energy controls the physical use of the property under the lease. Revenues relating to the Gathering Agreement is recognized in the period service is provided. Under this arrangement, the Partnership receives a fee or fees for services provided. The revenue the Partnership recognizes from gathering and transportation services is generally directly related to the volume of oil and natural gas that flows through its systems.

Production

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 and expenses for these arrangements is recognized based on the information provided to us by the operators.

We additionally recognize and present changes in the fair value of our commodity derivative instruments within natural gas sales and oil sales in the consolidated statements of operations, which is accounted for under ASC 815, "Derivatives and Hedging".

Accounts Receivable, Net

Our accounts receivable are primarily from our contractual agreements with Sanchez Energy and its subsidiaries, operators of our oil and natural gas properties and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted. Our allowance for doubtful accounts was $0.4 million as of December 31, 2019 and 2018.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. We place our cash with high credit quality financial institutions. We place our derivative financial instruments with financial institutions that participate in our Credit Agreement and maintain an investment grade credit rating. Substantially all of our accounts receivable are due from operators of our oil and natural gas properties. These sales are generally unsecured and, in some cases, may carry a parent guarantee. We routinely assess the financial strength of our customers. Bad debt expense is recognized on an account-by-account review and when recovery is not probable. We have no off-balance-sheet credit exposure related to our operations or customers.

Sanchez Energy accounted for 86% and 71% of total revenue for the years ended December 31, 2019 and 2018, respectively. We are highly dependent upon Sanchez Energy as our most significant customer, and we expect to derive a substantial portion of our revenue from Sanchez Energy in the foreseeable future. Accordingly, we are indirectly subject to the business risks of Sanchez Energy.

Income Taxes

SNMP and each of its wholly-owned subsidiary LLCs are treated as a partnership for federal and state income tax purposes. All of our taxable income or loss, which may differ considerably from net income or loss reported for financial reporting purposes, is passed through to the federal income tax returns of our members. As such, no federal income tax for these entities has been provided for in the accompanying financial statements.

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 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.

Asset Retirement Obligations

Asset retirement obligations represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, asset life, inflation and the credit-adjusted risk-free rate. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset and is included in accretion expense in the our consolidated statements of operations.

To estimate the fair value of an asset retirement obligation, the Partnership employs a present value technique, which reflects certain assumptions, including its credit-adjusted risk-free interest rate, inflation rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

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. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. 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. As more fully described in Note 8 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

All other properties, including the gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

Estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Oil and natural gas properties are reviewed for impairment 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. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 8 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements for additional information.

Reserves of Natural Gas, NGLs and Oil

Our estimate of proved reserves is based on the quantities of natural gas, NGLs and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of the reserve report prepared by Ryder Scott, an independent oil and natural gas consulting firm. On an annual basis, our proved reserve estimates and the reserve report prepared by Ryder Scott are reviewed by the Audit Committee and the Board. Our financial statements for 2019 and 2018 were prepared using Ryder Scott's estimates of our proved reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the actual quantities of oil and natural gas eventually recovered.

Unit-Based Compensation

The Partnership records unit-based compensation expense for awards granted in accordance with the provisions of Accounting Standards Codification ("ASC") Topic 718, "Compensation—Stock Compensation." Unit-based compensation expense for these awards is based on the grant-date fair value and recognized over the vesting period using the straight-line method.

Investments

We follow the equity method of accounting when we do not exercise control over the investee, but we can exercise significant influence over the operating and financial policies of the investee. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received. We evaluate our equity investments for impairment when evidence indicates the carrying amount of our investment is no longer recoverable. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. When the estimated fair value of an equity investment is less than its carrying value and the loss in value is determined to be other than temporary, we recognize the excess of the carrying value over the estimated fair value as an impairment loss within earnings from equity investments in our consolidated statements of operations.

Earnout Derivative

As part of the Carnero Gathering Transaction (defined in Note 12 "Investments"), we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. The earnout derivative is accounted for under ASC 815, and we measure its fair value 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.

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 $76.6 and $83.6 million for the years ended December 31, 2019 and 2018, respectively. We disaggregate revenue based on type of revenue and product type. In selecting the disaggregation categories, we considered a number of factors, including disclosures presented outside the financial statements, such as in our earnings release and investor presentations, information reviewed internally for evaluating performance, and other factors used by the Partnership or the users of its financial statements to evaluate performance or allocate resources. We have concluded that disaggregating revenue by type of revenue and product type appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

Midstream Segment

The Seco Pipeline Transportation Agreement is the only contract that we account for under ASC 606. The Catarina Midstream Gathering Agreement (as defined in Note 14 "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 revenue in our consolidated statements of operations. Both of these contracts are further discussed in Note 14 "Related Party Transactions."

We account for income from our unconsolidated equity method investments as earnings from equity investments in our consolidated statements of operations. Earnings from these equity method investments are further discussed in Note 12 "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 the 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 treat these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. The Seco Pipeline Transportation Agreement requires payment within 30 days following the calendar month of delivery.

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

For forms of variable consideration that are not associated with a specific volume (such as late payment fees) and thus do not meet allocation exception, estimation is required. These fees, however, are immaterial to our 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 December 31, 2019, and 2018 our accounts receivable from contracts with customers were $1.1 million and $0.6 million, respectively, and are presented within accounts receivable – related entities on the consolidated balance sheets.

4. ACQUISITIONS AND DIVESTITURES

Louisiana Divestiture

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

Briggs Divestiture

In April 2018, we entered into a purchase and sale agreement to sell specified wellbores and related assets and interests in La Salle County Texas (the “Briggs Assets”) for a base purchase price of approximately $4.5 million which, after giving effect to purchase price adjustments, was reduced to approximately $4.2 million in cash consideration (the “Briggs Divestiture”). In addition, other than limited obligations that we retained, the buyer agreed to assume all obligations relating to the Briggs Assets, including all plugging and abandonment costs, that may arise on or after March 1, 2018. The Briggs Divestiture closed on April 30, 2018 and we recorded a gain of approximately $1.8 million on the sale.

Cola Divestiture

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

5. FAIR VALUE MEASUREMENTS

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

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

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

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

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

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of 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 liability	$ —	$ (759)	$ —	$ (759)
Midstream derivative instrument				
Earnout derivative liability	—	—	—	—
Other liabilities				
Warrant	—	(629)	—	(629)
Total	$ —	$ (1,388)	$ —	$ (1,388)

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2018 (in thousands):

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

As of December 31, 2019 and 2018, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of Topic 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. We periodically review oil and natural gas properties and related equipment for impairment when facts and circumstances indicate that their carrying values may not be recoverable.

A reconciliation of the beginning and ending balances of the Partnership’s asset retirement obligations is presented in Note 10 ‘‘Asset Retirement Obligation.’’

Class C Preferred Units – As part of the Exchange (defined in Note 17 “Partners’ Capital”), Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and the Warrant in a privately negotiated transaction. The Class C Preferred Units were measured using valuation techniques that convert a future obligation to a single discounted amount. We have therefore classified the fair value measurements of the Class C Preferred units as Level 2 and are presented within “Class C Preferred Units” on the Consolidated Balance Sheets.

Seco Pipeline – We recorded a non-cash impairment charge of $32.1 million to impair the Seco Pipeline. The carrying value of the Seco Pipeline was reduced to a fair value of zero, estimated based on an 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 (defined in Note 7 "Debt") approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. The Credit Agreement is discussed further in Note 7 "Debt."

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate derivatives as of December 31, 2019.

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 consolidated balance sheets.

Earnout Derivative – As part of the Carnero Gathering Transaction (defined in Note 12 "Investments"), we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. The earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. We have therefore classified the fair value measurements of the earnout derivative as Level 3 inputs.

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

	Years Ended December 31,	
	2019	2018
Beginning balance	$ (5,856)	$ (6,402)
Gain on earnout derivative	5,856	546
Ending balance	$ —	$ (5,856)
Gain included in earnings related to derivatives still held as of December 31, 2019 and December 31, 2018	$ 5,856	$ 546

6. DERIVATIVE AND FINANCIAL INSTRUMENTS

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

Under Topic 815, “Derivatives and Hedging”, all derivative instruments are recorded on the 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 consolidated statements of operations.

As of December 31, 2019, we had the following derivative contracts in place, all of which are accounted for as mark-to-market activities:

MTM Fixed Price Swaps – NYMEX (Henry Hub)

	Three Months Ended (volume in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85

MTM Fixed Price Basis Swaps – West Texas Intermediate (WTI)

	Three Months Ended (volume in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50

The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the years ended December 31, 2019 and 2018 (in thousands):

	Years Ended December 31,	
	2019	2018
Beginning fair value of commodity derivatives	$ 3,914	$ 1,231
Net gain (loss) on crude oil derivatives	(4,031)	1,400
Net gain (loss) on natural gas derivatives	259	(84)
Net settlements paid (received) on derivative contracts:		
Oil	(807)	1,330
Natural gas	(94)	37
Ending fair value of commodity derivatives	$ (759)	$ 3,914

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

Derivative Type	Location of Gain (Loss) in Income	Years Ended December 31, 2019	2018
Commodity – Mark-to-Market	Oil sales	$ (4,031)	$ 1,400
Commodity – Mark-to-Market	Natural gas sales	259	(84)
		$ (3,772)	$ 1,316

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with three counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments. As of December 31, 2019 and 2018, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Earnout Derivative

Refer to Note 5 "Fair Value Measurements".

7. 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 (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.

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 December 31, 2019, the borrowing base under the Credit Agreement was $235.5 million and we had $150.0 million of debt outstanding, consisting of $145.0 million under the Term Loan and $5.0 million under the Revolving Loan. We are required to make mandatory amortizing payments of outstanding principal on the Term Loan of $10 million per fiscal quarter. The maximum revolving credit amount is $20.0 million leaving us with $15.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of December 31, 2019.

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 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 December 31, 2019, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt 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.

Debt Issuance Costs

As of December 31, 2019 and 2018, our unamortized debt issuance costs were approximately $1.2 million and $1.4 million, respectively. These costs are amortized to interest expense in our consolidated statements of operations over the life of our Credit Agreement. Amortization of debt issuance costs recorded during the years ended December 31, 2019 and 2018 were approximately $1.3 million and $0.8 million, respectively.

8. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

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

	December 31,	
	2019	**2018**
Gathering and transportation assets		
Midstream assets	$ 186,941	$ 186,406
Less: Accumulated depreciation, amortization and impairment	(74,648)	(34,598)
Total gathering and transportation assets, net	$ 112,293	$ 151,808

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

	December 31,	
	2019	**2018**
Oil and natural gas properties and related equipment		
Proved property	$ 112,476	$ 112,173
Less: Accumulated depreciation, depletion, amortization and impairments	(69,541)	(65,647)
Total oil and natural gas properties and equipment, net	$ 42,935	$ 46,526

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

Proved Reserves. Accounting rules require that we price our oil and natural gas proved reserves at the preceding twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Such SEC-required prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Our proved reserve estimates exclude the effect of any derivatives we have in place.

Our estimate of proved reserves is based on the quantities of natural gas, NGLs, and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Proved reserves are calculated based on various factors, including consideration of an independent reserve engineers' report on proved reserves and an economic evaluation of all of our properties on a well-by-well basis. The process used to complete the estimates of proved reserves at December 31, 2019 and 2018 is described in detail in Note 20 "Supplemental Information on Oil and Natural Gas Producing Activities."

Reserves and their relation to estimated future net cash flows impact depletion and impairment calculations. As a result, adjustments to depletion and impairments are made concurrently with changes to reserve estimates. The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

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 3 to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

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 significant inputs, besides reserves, used to determine the fair values of proved properties include estimates of: (i) future operating and development costs; (ii) future commodity prices; and (iii) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Cash flow estimates for impairment testing exclude derivative instruments.

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

	Years Ended December 31,	
	2019	**2018**
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 3,942	$ 4,798
Depreciation and amortization of gathering and transportation related assets	7,931	7,729
Amortization of intangible assets	13,460	13,460
Total Depreciation, depletion and amortization	$ 25,333	$ 25,987

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.

On January 13, 2020, we received a written notice from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective February 12, 2020. For the year ended December 31, 2019, we recorded a non-cash charge of $32.1 million, to impair the Seco Pipeline. For the year ended December 31, 2018, we recorded no impairment charges.

Asset Retirement Obligation. As described in Note 10 "Asset Retirement Obligation," estimated asset retirement costs are recognized when the asset is acquired or placed in service. Costs associated with oil and natural gas properties are amortized over proved developed reserves using the units-of-production method. Costs associated with gathering and transportation assets are depreciated using the straight-line method over the useful lives of the asset. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Exploration and Dry Hole Costs. Exploration and dry hole costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs and the impairment, amortization and abandonment associated with leases on our unproved properties. All such costs on oil and natural gas properties relating to unsuccessful exploratory wells are charged to expense as incurred. We recorded no exploration or dry hole costs for the years ended December 31, 2019 and 2018.

Materials and Supplies. Materials and supplies consist of well equipment, parts and supplies. They are valued at the lower of cost or market, using either the specific identification or first-in first-out method, depending on the inventory type. Materials and supplies are capitalized as used in the development or support of our oil and natural gas properties.

9. PROVISION FOR INCOME TAXES

Publicly traded partnerships like ours are treated as corporations unless they have 90% or more in qualifying income (as that term is defined in the Internal Revenue Code). We satisfied this requirement in each of the years ended December 31, 2019 and 2018 and, as a result, are not subject to federal income tax. However, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Net earnings for financial reporting purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. We do not have access to information regarding each partner's individual tax basis in our limited partner interests.

Provision for income taxes reflects franchise tax obligations in the state of Texas (the "Texas Margin Tax"). Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

Our federal and state income tax provision (benefit) is summarized below:

	Years Ended December 31,	
	2019	**2018**
Current:		
Federal	$ —	$ —
State	328	64
Total current	328	64
Deferred:		
Federal	—	—
State	(126)	126
Total deferred	(126)	126
Total provision for income taxes	$ 202	$ 190

A reconciliation of the provision for (benefit from) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income (loss) before income taxes is as follows (in thousands):

	Years Ended December 31,	
	2019	2018
Pre-tax net book income (loss)	$ (50,940)	$ 15,881
Texas Margin Tax [(a)]	126	267
Return to accrual	76	9
Valuation allowance	—	(86)
Provision for income taxes	$ 202	$ 190
Effective income tax rate	(0.40%)	1.20%

(a) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated (in thousands):

	December 31,	
	2019	2018
Deferred tax assets (liabilities):		
Derivative assets	$ (23)	$ (15)
Depreciable, depletable property, plant and equipment	21	(112)
Other	2	1
Deferred tax assets (liabilities):	—	(126)
Valuation allowance	—	—
Total deferred tax assets (liabilities)	$ —	$ (126)

Deferred tax assets which required valuation allowances were related to assets sold in 2018. Therefore, the valuation allowance is no longer necessary and was removed as of December 31, 2018.

As of December 31, 2019 and 2018, the Partnership had no material uncertain tax positions.

The Partnership files income tax returns in the U.S. and various state jurisdictions. The Partnership is no longer subject to examination by federal income tax authorities prior to 2016. State statutes vary by jurisdiction.

10. ASSET RETIREMENT OBLIGATION

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

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

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

	December 31, 2019	December 31, 2018
Asset retirement obligation, beginning balance	$ 6,200	$ 6,074
Liabilities added from escalating working interests	172	288
Sales	—	(613)
Revisions to cost estimates	—	(46)
Accretion expense	526	497
Asset retirement obligation, ending balance	$ 6,898	$ 6,200

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. In 2019 and 2018, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs. During the year ended December 31, 2018, obligations were sold as part of the Briggs Divestiture, Louisiana Divestiture and Cola Divestiture.

11. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes $145.2 million related to the Gathering Agreement with Sanchez Energy that was entered into as part of the Western Catarina Midstream transaction. Pursuant to the 15-year agreement, Sanchez Energy tenders all of its crude oil, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15 year life of the agreement.

Amortization expense for the years ended December 31, 2019 and 2018 was $13.5 million, respectively. These costs are amortized to depreciation, depletion, and amortization expense in our consolidated statement of operations. Intangible assets as of December 31, 2019 and 2018 are detailed below (in thousands):

	December 31, 2019	December 31, 2018
Beginning balance	$ 158,706	$ 172,166
Amortization	(13,460)	(13,460)
Ending balance	$ 145,246	$ 158,706

12. INVESTMENTS

In July 2016, we completed a transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Gathering, LLC (“Carnero Gathering”), a joint venture that was 50% owned and operated by Targa Resources Corp. (NYSE: TRGP) (“Targa”), for an initial payment of approximately $37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million as of the acquisition date (the “Carnero Gathering Transaction”). The fair value of the intangible asset for the contractual customer relationship related to Carnero Gathering was valued at approximately $13.0 million. This amount is being amortized over a contract term of 15 years and decreases earnings from equity investments in our consolidated statements of operations. As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. See Note 5 “Fair Value Measurements” for further discussion of the earnout derivative.

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

In May 2018, we executed a series of agreements with Targa and other parties pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering and Carnero Processing (the "Carnero JV Transaction") to form an expanded 50 / 50 joint venture in South Texas, within Carnero G&P, LLC ("the Carnero JV"), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant ("Silver Oak II"), located in Bee County Texas, to the Carnero JV, which expands the processing capacity of the Carnero JV from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the 45 miles of high pressure natural gas gathering pipelines owned by Carnero Gathering that connect Western Catarina Midstream to nearby pipelines and the Raptor Gas Processing Facility (the "Carnero Gathering Line") to the Carnero JV resulting in the Carnero JV owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) the Carnero JV received a new dedication from Sanchez Energy and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Sanchez Energy's Comanche Asset pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the Carnero JV limited by the capacity of the Raptor Gas Processing Facility. As a result of the Carnero JV Transaction we now record our share of earnings and losses from the Carnero JV using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. The HLBV is a balance-sheet approach that calculates the amount we would have received if the Carnero JV were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our 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 December 31, 2019, the Partnership had paid approximately $124.1 million for its investment in the Carnero JV related to the initial payments and contributed capital. The Partnership has accounted for this investment using the equity method. Targa is the operator of the Carnero JV and has significant influence with respect to the normal day-to-day capital and operating decisions. We have included the investment balance in the equity investments caption on our consolidated balance sheets. For the year ended December 31, 2019, the Partnership recorded earnings of approximately $4.0 million in equity investments from the Carnero JV, which was offset by approximately $1.2 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 consolidated statements of operations. Cash distributions of approximately $17.2 million were received during the year ended December 31, 2019.

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

	Years Ended December 31,	
	2019	**2018**
Sales	$ 159,508	$ 321,607
Total expenses	145,837	290,073
Net income	$ 13,671	$ 31,534

13. COMMITMENTS AND CONTINGENCIES

As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. This earnout has an approximate value of zero as of December 31, 2019. For the year ended December 31, 2019 payments totaling approximately $32.0 thousand were made. For the year ended December 31, 2018, natural gas received did not exceed the threshold.

14. RELATED PARTY TRANSACTIONS

Sanchez-Related Agreements

We are controlled by our general partner. The sole member of our general partner is Manager, which has no officers. The sole manager and member of Manager is SP Capital Holdings, LLC, which has no officers. The co-managers of SP

Capital Holdings, LLC are Antonio R. Sanchez, III, a member of and Chairman of the Board; Eduardo A. Sanchez, a member of the Board; Patricio D. Sanchez, a member of the Board and the President and Chief Operating Officer of our general partner; and their father, Antonio R. Sanchez, Jr. SP Capital Holdings, LLC is owned by Antonio R. Sanchez, III, Eduardo A. Sanchez , and Patricio D. Sanchez, along with their sister, Ana Lee Sanchez Jacobs, and Antonio R. Sanchez, Jr. In May 2014, we entered into the Services Agreement with Manager pursuant to which Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, and acquisition, disposition and financing services. In connection with providing services under the Services Agreement, Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, is paid in cash unless Manager elects for such fee to be paid in our equity with the exception of the following modified payment terms under the Services Agreement. In November 2019, a letter agreement was executed modifying the payment terms under the Services Agreement beginning with the fee for the quarter ended September 30, 2019. Under the modified terms, payment is being withheld until such time as all issued and outstanding Class C Units have been redeemed. Following the redemption of all issued and outstanding Class C Units the fee will be paid in our equity. As of December 31, 2019, the amount owed under the Services Agreement was $4.9 million and is presented within long term accrued liabilities - related entities on the consolidated balance sheet. If all Class C Units had been redeemed on December 31, 2019, we would issue approximately 11.4 million common units to Manager to settle the portion of the liability related to the November 2019 letter agreement. During the years ended December 31, 2019 and 2018, we incurred costs of approximately $7.3 million and $8.6 million, respectively, to Manager under the Services Agreement. Manager utilizes SOG to provide the services under the Services Agreement. The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless both Manager and the Partnership provide notice of termination to the other with at least 180 days' notice.

SOG, headquartered in Houston, Texas, is a private full-service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. SOG has successfully built and operated extensive midstream and gathering assets associated with its aforementioned development activities. The Chairman of the Board, Antonio R. Sanchez, III, the President and Chief Operating Officer of our general partner as well as one of our directors, Patricio D. Sanchez, one of our directors, Eduardo A. Sanchez, along with their immediate family members Ana Lee Sanchez Jacobs and Antonio R. Sanchez, Jr., collectively, either directly or indirectly, own a majority of the equity interests of SOG. In addition, Antonio R. Sanchez, III and Patricio D. Sanchez are Co-Presidents of SOG; Antonio R. Sanchez, Jr. is the Chief Executive Officer and sole director of SOG; Ana Lee Sanchez Jacobs is an Executive Vice President of SOG; and Gerald F. Willinger is an Executive Vice President of SOG.

Sanchez-Related Transactions

We have entered into several transactions with Sanchez Energy since January 1, 2018.

In conjunction with the acquisition of Western Catarina Midstream, we entered into a 15-year gas gathering agreement with Sanchez Energy, pursuant to which Sanchez Energy agreed to tender all of its crude oil, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres in the Western Catarina area of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the "Gathering Agreement"). During the first five years of the term of the Gathering Agreement, Sanchez Energy is required to meet a minimum quarterly volume delivery commitment of 10,200 Bbls per day of oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. Sanchez Energy is required to pay gathering and processing fees of $0.96 per 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, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by Sanchez Energy based on water that is delivered through the gathering system through March 31, 2018, and have subsequently agreed to continue the incremental infrastructure fee on a month-to-month basis. For the years ended December 31, 2019 and 2018, Sanchez Energy paid us approximately $59.1 million and $57.9 million, respectively, pursuant to the terms of the gathering and processing agreement.

As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at Carnero Gathering's delivery points from Sanchez Energy and other producers. For the year ended December 31, 2019, payments totaling approximately $32.0 thousand were made. For the year ended December 31, 2018, natural gas did not exceed the threshold.

In September 2017, we entered into the Seco Pipeline Transportation Agreement. For the years ended December 31, 2019 and 2018, Sanchez Energy paid us approximately $6.8 million and $7.2 million, respectively, pursuant to the terms of that agreement. On January 13, 2020, we received a written notice from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective February 12, 2020.

In May 2018, the Carnero JV, which is operated by Targa, received a dedication from Sanchez Energy and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Sanchez Energy's Comanche Asset pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the joint ventures limited by the capacity of the Raptor Gas Processing Facility.

As of December 31, 2019 and 2018, the Partnership had a net receivable from related parties of approximately $6.7 million, respectively, which are included in accounts receivable – related entities in the consolidated balance sheets. As of December 31, 2019 and 2018, the Partnership also had a net payable to related parties of approximately $5.5 million, and $5.6 million, respectively. The net receivable/payable as of December 31, 2019 consist primarily of revenues receivable from oil and natural gas production and transportation, offset by costs associated with that production and transportation.

Sanchez Energy is an independent exploration and production company focused on the acquisition and development of U.S. onshore unconventional oil and natural gas resources, with a current focus on the horizontal development of significant resource potential from the Eagle Ford Shale in South Texas where it has assembled approximately 415,000 gross leasehold acres (215,000 net acres). The Chairman of the Board, Antonio R. Sanchez, III, is Sanchez Energy's Chief Executive Officer and a member of its board of directors. A member of the Board, Eduardo A. Sanchez, is the former President of Sanchez Energy. The President and Chief Operating Officer of our general partner, Patricio D. Sanchez, who is also a member of the Board, is an Executive Vice President of Sanchez Energy. Antonio R. Sanchez, Jr., the father of Antonio R. Sanchez, III, Eduardo A. Sanchez, and Patricio D. Sanchez, is the Executive Chairman of the board of directors of Sanchez Energy. Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez beneficially own 6.1%, 3.0%, 1.1% and 1.2%, respectively, of Sanchez Energy's shares outstanding as of March 13, 2020. As of March 13, 2020, Sanchez Energy indirectly, through one of its wholly owned subsidiaries, beneficially owns approximately 11.4% of the outstanding common units of SNMP. The employees of SOG, including Kirsten A. Hink, our Chief Accounting Officer, provide services to both us and Sanchez Energy.

15. UNIT-BASED COMPENSATION

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

As of December 31, 2019, 840,811 common units remained available for future issuance to participants under the LTIP.

	Number of Restricted Units		Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2017	283,138	$	14.64
Granted	622,534		11.94
Vested	(301,005)		13.60
Returned/Cancelled	(90,973)		12.77
Outstanding at December 31, 2018	513,694	$	12.31

Granted	1,129,173		2.35
Vested	(382,690)		8.50
Returned/Cancelled	(104,710)		12.04
Outstanding at December 31, 2019	1,155,467	$	3.86

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.

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

16. DISTRIBUTIONS TO UNITHOLDERS

The table below reflects the payment of cash distributions on common units relating to the years ended December 31, 2019 and 2018.

Three months ended		Distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2018	$	0.4508	May 8, 2018	May 22, 2018	May 31, 2018
June 30, 2018	$	0.4508	August 8, 2018	August 21, 2018	August 31, 2018
September 30, 2018	$	0.1500	November 9, 2018	November 20, 2018	November 30, 2018
December 31, 2018	$	0.1500	February 7, 2019	February 20, 2019	February 28, 2019
March 31, 2019	$	0.1500	May 3, 2019	May 22, 2019	May 31, 2019

The table below reflects the payment of distributions on Class B Preferred Units relating to the years ended December 31, 2019 and 2018.

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

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

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"). Following the Exchange, no distribution was declared with respect to the Class B Preferred Units.

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

17. PARTNERS' CAPITAL

Outstanding Units

As of December 31, 2019, we had no Class B Preferred Units outstanding, 33,258,043 Class C Preferred Units outstanding and 20,087,462 common units outstanding, which included 1,155,467 unvested restricted common units issued under the LTIP.

Common Unit Issuances

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

Three months ended	Common units	Date of issuance
December 31, 2017	210,978	March 15, 2018
March 31, 2018	220,214	May 31, 2018
June 30, 2018	224,342	September 10, 2018
September 30, 2018	334,010	November 30, 2018
December 31, 2018	787,750	March 8, 2019
March 31, 2019	887,269	May 23, 2019
June 30, 2019	901,741	August 2, 2019

Class B Preferred Unit Offering

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

Under the terms of our partnership agreement, holders of the Class B Preferred Units received a quarterly distribution, at the election of the Board, of 10.0% per annum if paid in full in cash or 12.0% per annum if paid in part cash (8.0% per annum) and in part Class B Preferred PIK Units (4.0% per annum), as defined in the Second Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended Partnership Agreement"). Distributions were to be paid on or about the last day of each of February, May, August and November after the end of each quarter.

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

The Partnership elected to pay the second-quarter 2018 distribution on the Class B Preferred Units in part cash and part Class B Preferred PIK Units in accordance with the partnership agreement. Accordingly, the Partnership issued 310,009 Class B Preferred PIK Units on August 31, 2018, to Stonepeak.

The Class B Preferred Units are accounted for as mezzanine equity in the consolidated balance sheet consisting of the following (in thousands):

	December 31,	
	2019	2018
Mezzanine equity, beginning balance	$ 349,857	$ 343,912
Amortization of discount	1,708	2,358
Distributions	23,247	36,925
Distributions paid	(17,675)	(33,338)
Class B Preferred Unit exchange	(357,137)	—
Mezzanine equity, ending balance	$ —	$ 349,857

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

Class C Preferred Units

On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and the Warrant in a privately negotiated transaction (the "Exchange"). In connection with the Exchange, the Partnership entered into (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended Partnership Agreement) to set forth the terms of the Class C Preferred Units, (ii) the Amended and Restated Registration Rights Agreement with Stonepeak relating to the registered resale of common units issuable upon the exercise of the Warrant, and (iii) the Amended and Restated Board Representation and Standstill Agreement with Stonepeak.

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 will 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 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 the consolidated balance sheet consisting of the following (in thousands):

		December 31, 2019
Class C Preferred Units		
Private placement of Class C Preferred Units	$	353,500
Discount		(104,250)
Amortization of discount		13,129
Distributions		19,309
Class C Preferred Units, ending balance	$	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 consolidated balance sheet. Changes in the fair value of the Warrant are charged to interest expense in our 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 the 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.

18. 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):

	Years Ended December 31,			
	2019		2018	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 683	$ —	$ 953	$ —
Oil sales	9,512	—	21,272	—
Natural gas liquid sales	539	—	1,709	—
Gathering and transportation sales	—	6,825	—	6,651
Gathering and transportation lease revenues	—	59,090	—	53,025
Total segment revenues	10,734	65,915	23,934	59,676
Segment operating costs				
Lease operating expenses	5,879	1,499	6,719	1,145
Transportation operating expenses	—	11,553	—	12,316
Production taxes	621	—	1,104	—
Gain on sale of assets	—	—	(3,186)	—
Depreciation, depletion and amortization	3,942	21,391	4,798	21,189
Asset impairments	—	32,119	—	—
Accretion expense	200	326	198	299
Total segment operating costs	10,642	66,888	9,633	34,949
Segment other income				
Earnings from equity investments	—	2,831	—	12,859
Total segment other income	—	2,831	—	12,859
Segment operating income	$ 92	$ 1,858	$ 14,301	$ 37,586

	Years Ended December 31,	
	2019	2018
Reconciliation of segment operating income to net income (loss)		
Total production operating income	$ 92	$ 14,301
Total midstream operating income	1,858	37,586
Total segment operating income	1,950	51,887
General and administrative expense	(17,610)	(23,653)
Unit-based compensation expense	(1,351)	(1,938)
Interest expense, net	(39,789)	(10,961)
Other income	5,860	546
Income tax expense	(202)	(190)
Net income (loss)	$ (51,142)	$ 15,691

The following table summarizes the total assets and capital expenditures by operating segment as of December 31, 2019 and 2018 (in thousands):

	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

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

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

Revenue from Sanchez Energy earned in our Midstream segment accounted for 86% and 71% of total revenue for the years ended December 31, 2019 and 2018, respectively. Because all remaining production properties are non-operated, there are no customers in the Production segment that exceed 10% of the Partnership's consolidated revenue.

19. 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 $100.3 million.

As of December 31, 2019, the Partnership had invested approximately $124.1 million in the Carnero JV and no debt has been incurred by the Carnero JV. We have included this VIE in other assets, equity investments on the balance sheet.

Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Partnership's maximum exposure to loss as of December 31, 2019 and 2018 (in thousands):

	December 31,	
	2019	2018
Acquisitions, earnout and capital investments	$ 128,140	$ 127,899
Earnings in equity investments	25,976	23,144
Distributions received	(53,805)	(36,578)
Maximum exposure to loss	$ 100,311	$ 114,465

20. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

The Supplementary Information on Oil and Natural Gas Producing Activities is presented as required by the appropriate authoritative guidance. The supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred for the acquisition of oil and natural gas producing activities, exploration and development activities and the results of operations from oil and natural gas producing activities.

Supplemental information is also provided for per unit production costs; oil and natural gas production and average sales prices; the estimated quantities of proved oil and natural gas reserves; the standardized measure of discounted future net cash flows associated with proved reserves and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved reserves.

Costs

The following table sets forth our capitalized costs as of December 31, 2019 and 2018 (in thousands):

	December 31,	
	2019	2018
Capitalized costs at the end of the period:[(a)]		
Oil and natural gas properties and related equipment (successful efforts method)		
Proved property	$ 112,476	$ 112,173
Less: Accumulated depreciation, depletion, amortization and impairments	(69,541)	(65,647)
Oil and natural gas properties and equipment, net	$ 42,935	$ 46,526

(a) Capitalized costs include the cost of equipment and facilities for our oil and natural gas producing activities. Proved property costs include capitalized costs for leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment. Unproved property costs include capitalized costs for oil and natural gas leaseholds where proved reserves do not exist.

The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2019 and 2018 (in thousands):

	Years Ended December 31,	
	2019	2018
Costs incurred for the period:		
Acquisition of properties		
Proved	$ —	$ —
Development costs	131	11
Oil and natural gas properties and equipment, net	$ 131	$ 11

The development costs for the years ended December 31, 2019 and 2018 primarily represent costs related to recompletions.

We had no exploration and dry hole costs in 2019 and 2018.

Results of Operations

The revenues and expenses associated directly with oil and natural gas producing activities are reflected in the Consolidated Statements of Operations. All of our oil and natural gas producing activities are located in the United States.

Net Proved Reserves of Natural Gas, NGLs and Oil

The following table sets forth information with respect to changes in proved developed and undeveloped reserves. This information excludes reserves related to royalty and net profit interests. All of our reserves are located in the United States.

	Total (MMBoe)	Oil (in MMBoe)	Natural Gas (in MMBoe)	Natural Gas Liquids (in MMBoe)
Net proved reserves				
December 31, 2017	5,265	3,246	1,109	910
Sales of reserves in place	(1,105)	(272)	(322)	(511)
Revisions of previous estimates	(268)	(199)	(261)	192
Production	(439)	(296)	(72)	(71)
December 31, 2018	3,453	2,479	454	520
Sales of reserves in place	—	—	—	—
Revisions of previous estimates	(145)	(10)	(67)	(68)
Production	(309)	(228)	(39)	(42)
December 31, 2019	2,999	2,241	348	410
Proved developed reserves:				
December 31, 2018	3,453	2,479	454	520
December 31, 2019	2,999	2,241	348	410

Reserves and Related Estimates

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters.

Our year end December 31, 2019 and 2018, proved reserve estimates were 3.0 MMBoe and 3.5 MMBoe, respectively. Reserve estimates for those periods were prepared by, Ryder Scott, an independent petroleum engineering firm, and are used for the applicable disclosures in our financial statements.

Our 2019 estimates of total proved reserves decreased 0.5 MMBoe from 2018 due to production of 0.3 MMBoe and revisions of previous estimates of 0.2 MMBoe. For proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $59.55 per Bbl for oil, $13.68 per Bbl for NGLs and $2.66 per Mcf for natural gas.

Our 2018 estimates of total proved reserves decreased 1.8 MMBoe from 2017 primarily due to a decrease in reserves of 1.1 MMBoe due to the Louisiana Divestiture, Briggs Divestiture and Cola Divestiture. For proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $66.95 per Bbl for oil, $23.00 per Bbl for NGLs and $3.21 per Mcf for natural gas.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves, Including a Reconciliation of Changes Therein

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and natural gas reserves. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying the SEC-required prices of oil and natural gas relating to our proved reserves to the year-end quantities of those reserves. Future cash inflows exclude the impact of our hedging program. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because the Partnership is a non-taxable entity.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present values. In addition, variations from expected production rates could result directly or indirectly from factors outside of our control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

The following table summarizes the standardized measure of estimated discounted future cash flows from the oil and natural gas properties (in thousands):

	Years Ended December 31, 2019	2018
Future cash inflows	$ 144,628	$ 186,675
Future production costs	(80,007)	(99,187)
Future estimated development costs	(3,400)	(4,043)
Future net cash flows	61,221	83,445
10% annual discount for estimated timing of cash flows	(22,871)	(31,199)
Standardized measure of discounted estimated future net cash flows related to proved oil and natural gas reserves	$ 38,350	$ 52,246

The following table summarizes the principal sources of change in the standardized measure of estimated discounted future net cash flows (in thousands):

	Years Ended December 31, 2019	2018
Beginning of the period	$ 52,246	$ 56,697
Sales and transfers of oil and natural gas, net of production costs	(8,006)	(14,795)
Net changes in prices and production costs related to future production	(7,330)	17,392
Changes in development costs	35	207
Revisions of previous quantity estimates	(1,942)	(4,203)
Purchases and sales of reserves in place	—	(5,423)
Accretion discount	5,225	5,670
Change in production rates, timing, and other	(1,878)	(3,299)
Standardized measure of discounted future net cash flows related to proved oil and natural gas reserves	$ 38,350	$ 52,246

21. SUBSEQUENT EVENTS

On February 13, 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. As required by the Amended Partnership Agreement, the Board declared a fourth quarter distribution on the Class C Preferred Units payable 100% in Class C Preferred PIK Units. Accordingly, the Partnership declared an aggregate distribution of 1,039,314 Class C Preferred PIK Units, which was paid on February 28, 2020 to holders of record on February 20, 2020.

On January 13, 2020, we received written notice of termination from Sanchez Energy terminating the Seco Pipeline Transportation Agreement effective February 12, 2020.

Since December 31, 2019, the Partnership paid $6.0 million in principal outstanding under the Credit Agreement resulting in total debt outstanding of $144.0 million under the Credit Agreement as of March 13, 2020.

Exhibit 4.3

Description of THE REGISTRANT'S Securities
REGISTERED PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934

As of December 31, 2019, Sanchez Midstream Partners LP (the "Partnership," "we" or "us") had a single class of security registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): common units representing limited partner interests in the Partnership ("common units"). We also had a single Warrant Exercisable for Junior Securities (the "2019 Warrant") issued and outstanding, which is exercisable for Junior Securities, including common units.

The following description is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (our "partnership agreement"), which is incorporated by reference as Exhibit 3.4 to the Annual Report on Form 10-K, of which this Exhibit 4.3 is a part, and (ii) the 2019 Warrant, which is incorporated by reference as Exhibit 10.27 to the Annual Report on Form 10-K of which this Exhibit 4.3 is a part. Please read and refer to the partnership agreement, the applicable provisions of the Delaware Act and the 2019 Warrant, for additional information. References to our "general partner," refer to Sanchez Midstream Partners GP, LLC. Capitalized terms used but not defined herein have the meanings ascribed to them in the partnership agreement.

DESCRIPTION OF THE COMMON UNITS

The Common Units

The common units represent limited partner interests in us that entitle the holders thereof to the rights and privileges specified to limited partners set forth in our partnership agreement, including the right to participate in Partnership distributions.

Listing of Common Units

Our common units are traded on the NYSE American under the trading symbol "SNMP".

Transfer Agent and Registrar

Duties

Computershare Trust Company, N.A. serves as the registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There is no charge to unitholders for disbursements of our cash distributions. We indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for their activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed or a successor has not accepted its appointment, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

Common units are "securities" as defined in the Securities Act, and are transferable according to the laws governing transfers of securities. In addition to the other rights acquired upon transfer, the transferee of the common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to enter into our partnership agreement;
- automatically becomes bound by the terms and conditions of our partnership agreement; and
- makes the consents, acknowledgement and waivers contained in our partnership agreement, all with or without the execution of the partnership agreement by such transferee.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Number of Common Units

As of December 31, 2019, we had 20,087,462 common units issued and outstanding; 10,910,828 common units were held by the public; and 9,176,634 common units were held by affiliates of our general partner.

PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Cash Distribution Policy

Distributions of Available Cash

Our partnership agreement requires that, on or about the last day of each of February, May, August and November, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter, the sum of all cash and cash equivalents on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business (including cash reserves for our future capital expenditures and anticipated future debt service requirements) subsequent to that quarter;
  - comply with applicable law, any of our debt instruments or other agreements; or

- provide funds for distributions to our unitholders for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the cash portion of any distributions on our Class C Preferred Units or minimum quarterly distribution on our common units with respect to such quarter);

- *plus*, if our general partner so determines, all or any portion of additional cash and cash equivalents on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Under our partnership agreement, working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to unitholders, and with the intent of the borrower to repay such borrowings within twelve months with funds other than from additional working capital borrowings.

Class C Preferred Units

Under the terms of our partnership agreement, commencing with the quarter ended on June 30, 2019, the Class C Preferred Units receive a quarterly distribution of, at the election of the Board of Directors, (i) with respect to any distribution made with respect to the quarter ended June 30, 2019, 10.0% per annum if paid in full in cash or 12.0% per annum if paid in paid-in-kind units; (ii) with respect to any distribution made with respect to any quarter beginning with and after the quarter ending September 30, 2019, through and including the quarter ending December 31, 2021, 12.5% per annum, regardless of whether paid in cash, paid-in-kind units or a combination thereof; and (iii) with respect to any distribution made with respect to any quarter beginning on or after January 1, 2022, 14.0% per annum, regardless of whether paid in cash, paid-in-kind units or a combination thereof.

Additionally, under the terms of our partnership agreement, until the first quarter in which no Class C Preferred Units remain outstanding, we are not permitted to, and are prohibited from declaring or making, any distributions, redemptions or repurchases in respect of any Junior Securities, including common units, or any Parity Securities.

General Partner Interest and Incentive Distribution Rights

Our general partner currently owns a non-economic general partner interest in us which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

SP Holdings, LLC (“SP Holdings”), the sole member of our general partner, holds all of our incentive distribution rights, which entitles it to receive increasing percentages, up to a maximum of 35.5%, of the available cash we distribute from operating surplus (as defined in our partnership agreement) after we have achieved the minimum quarterly distribution and the target distribution levels.

Percentage Allocation of Distributions from Operating Surplus

The following table illustrates the percentage allocation of distributions from operating surplus among our unitholders and SP Holdings (as the holder of our incentive distribution rights) at various distribution levels (1) pursuant to the distribution provisions of our partnership agreement, as well as (2) following a hypothetical reset of the target distribution levels based on the assumption that the quarterly distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.875.

Under our partnership agreement, our general partner has considerable discretion to determine the amount of available cash (as defined therein) for distribution each quarter to our unitholders, including discretion to establish cash reserves that would limit the amount of available cash eligible for distribution to our unitholders for any quarter. We do not guarantee that we will pay the target amount of the minimum quarterly distribution listed below (or any distributions at all) on our units in any quarter. The percentage interest set forth below for SP Holdings (1) assume that SP Holdings has not transferred its incentive distribution rights and (2) assume that we do not issue additional classes of equity securities. Additionally, as disclosed above under "—Class C Preferred Units" we are prohibited from making distributions to our common unitholders until the first quarter during which no Class C Preferred Units remain outstanding.

	Total Quarterly Distribution per Common Unit	Common Unitholders	SP Holdings
Minimum Quarterly Distribution	up to $0.50	100.0 %	0.0%
First Target Distribution	above $0.50 up to $0.575	100.0%	0.0%
Second Target Distribution	above $0.575 up to $0.625	87.0%	13.0%
Third Target Distribution	above $0.625 up to $0.875	77.0%	23.0%
Thereafter	above $0.875	64.5%	35.5%

Distributions of Cash Upon Liquidation

If we dissolve in accordance with our partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the holders of the incentive distribution rights, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of SP Holdings.

Adjustments to Capital Accounts

We will make adjustments to capital accounts upon the issuance of additional units. In doing so, we generally will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the holders of our incentive distribution rights in the same manner as we allocate gain or loss upon liquidation.

DESCRIPTION OF OUR PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. Please refer to our partnership agreement for additional information, which is incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.3 is a part. We summarize the following provisions of our partnership agreement elsewhere herein:

- information relating to the rights and preferences of holders of common units in and to Partnership cash distributions is summarized under "Provisions of Our Partnership Agreement Relating to Cash Distributions" above; and

- information relating to the transfer of common units is summarized under "Description of the Common Units—Transfer of Common Units" above.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that require the approval of a "unit majority" require the approval of a majority of the common units. Holders of Class C Preferred Units have voting rights identical to the voting rights of the common unitholders and vote together with the common units as a single class, such that the Class C Preferred Units (including, for the avoidance of doubt, the Class C Preferred PIK Units) will be entitled to one vote per Class C Preferred Unit, except that the Class C Preferred Units are entitled to vote as a separate class on any matter on which unitholders are entitled to vote that adversely affects the rights or preferences of the Class C Preferred Units in relation to other classes of partnership interests.

In voting their common units, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of Our Partnership Agreement." In addition, amendments to the partnership agreement pertaining to the Class C Preferred Units requires the consent of each holder of a Class C Preferred Unit, to the extent such amendment would adversely affect such holder.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances.
Dissolution of our partnership	Unit majority.
Continuation of our business upon dissolution	Unit majority.
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the common units and Class C Preferred Units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to September 30, 2024 in a manner that would cause a dissolution of our partnership.
Removal of our general partner	Not less than 66 2/3% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates.
Transfer of our general partner interest	No approval right.
Transfer of incentive distribution rights	No approval right.
Transfer of ownership interests in our general partner	No approval right.

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Sanchez Midstream Partners GP LLC as our general partner or otherwise change our management. Please read “—Change of Management Provisions” and “—Meetings; Voting.”

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);

- brought in a derivative manner on our behalf;

- asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;

- asserting a claim arising pursuant to any provision of the Delaware Act; or

- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), in each case regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. In addition, each party to such claims, suits, actions or proceedings irrevocably waives the right to trial by jury.

Although we believe these provisions will benefit us by providing increased consistency in the application of Delaware law for the specific types of actions and proceedings, the provisions may have the effect of discouraging lawsuits against our directors, officers, employees and agents. The enforceability of similar forum selection provisions in other companies’ certificates of incorporation or similar governing documents have been challenged in legal proceedings, and it is possible that, in connection with one or more actions described above, a court could find that the forum selection provision contained in our partnership agreement is inapplicable or unenforceable in such action or actions, including with respect to claims arising under the federal securities laws. Limited partners will not be deemed, by operation of the forum selection provision alone, to have waived claims arising under the federal securities laws and the rules and regulations thereunder.

The forum selection provision is intended to apply “to the fullest extent permitted by applicable law” to the above-specified types of actions and proceedings, including, to the extent permitted by the federal securities laws, to lawsuits asserting both the above-specified claims and federal securities claims. However, application of the forum selection provision may in some instances be limited by applicable law. Section 27 of the Exchange Act provides: “The district courts of the United States ... shall have exclusive jurisdiction of violations of the Exchange Act or the rules and regulations thereunder, and of all suits in equity and actions at law brought to enforce any liability or duty created by the Exchange Act or the rules and regulations thereunder.” As a result, the forum selection provision will not apply to actions arising under the Exchange Act or the rules and regulations thereunder. However, Section 22 of the Securities Act provides for concurrent federal and state court jurisdiction over actions under the Securities Act and the rules and regulations thereunder, subject to a limited exception for certain “covered class actions” as defined in Section 16 of the Securities Act and interpreted by the courts. Accordingly, we believe that the forum selection provision would apply to actions arising under the Securities Act or the rules and regulations thereunder, except to the extent a particular action fell within the exception for covered class actions.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that such limited partner otherwise acts in conformity with the provisions of our partnership agreement, that such limited partner's liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital that such limited partner is obligated to contribute to us for that such limited partner's common units plus that such limited partner's share of any undistributed profits and assets. However, if it were determined that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our subsidiary or any subsidiaries we may have in the future, or otherwise, it were determined that we were conducting business in any jurisdiction without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Partnership Interests; Preemptive Rights

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units that we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our current or future subsidiaries from issuing equity interests, which may effectively rank senior to the common units.

The holders of our common units do not have preemptive rights to acquire additional common units or other partnership securities.

Amendment of Our Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or to call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority. In addition, amendments to our partnership agreement pertaining to the Class C Preferred Units requires the consent of holders of a majority of the outstanding Class C Preferred Units, voting separately as a class with one vote per Class C Preferred Unit, to the extent such amendment would adversely affect the Class C Preferred Units.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without his consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict, change or modify in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provisions of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 75% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates).

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;

- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;

- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor any of our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for U.S. federal income tax purposes (to the extent not already so treated or taxed);

- a change in our fiscal year or taxable year and related changes;

- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), whether or not substantially similar to plan asset regulations currently applied or proposed;

- an amendment that our general partner determines to be necessary or appropriate in connection with the creation, authorization or issuance of additional partnership interests or the right to acquire partnership interests;

- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;

- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;

- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance in certain circumstances; or

- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement, without the approval of any limited partner, if our general partner determines that those amendments:

- do not adversely affect the limited partners, considered as a whole, or any particular class of limited partners, in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;

- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement;

- are necessary or appropriate in connection with the creation, authorization or issuance of any class or series of partnership securities; or

- are required to effect the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

Any amendment that our general partner determines adversely affects in any material respect one or more particular classes of limited partners will require the approval of at least a majority of the class or classes so affected, but no vote will be required by any class or classes of limited partners that our general partner determines are not adversely affected in any material respect. Any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that would reduce the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will neither result in a loss of limited liability to the limited partners nor result in our being treated as a taxable entity for federal income tax purposes in connection with any of the amendments. Any amendment relating to special unitholder meetings, notices of unitholder meetings, quorum and voting requirements, actions without a meeting and the amendment provisions in our partnership agreement require approval of 75% of our outstanding units. No amendments to our partnership agreement, other than those the general partner can adopt without unitholder approval or in connection with a merger or consolidation, will become effective without the approval of holders of at least 90% of the outstanding units, voting as a single class, unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the partnership securities to be issued do not exceed 20% of our outstanding partnership interests (other than incentive distribution rights) immediately prior to the transaction. If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, we have received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement and the Delaware Act. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;

- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;

- the entry of a decree of judicial dissolution of our partnership;

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or its withdrawal or removal following the approval and admission of a successor; or

- any other dissolution event as required by applicable Delaware law.

Upon a dissolution under the penultimate clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and

- neither we nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to September 30, 2024 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after September 30, 2024, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates, other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interest."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may appoint a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read "—Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 2/3% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of a unit majority. Notwithstanding that Stonepeak, as the holder of all of our Class C Preferred Units held approximately 63.1% of our outstanding units as of December 31, 2019, it has agreed that until the earlier of the occurrence of a material breach of the partnership agreement by us or our general partner, and the date on which all of the Class C Preferred Units have been redeemed, without the prior written consent of the Board of Directors, it will not vote in favor of removing our general partner.

In the event of the removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner and its affiliates for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest and the incentive distribution rights of the departing general partner and its affiliates for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value; if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, then the departing general partner's general partner interest and all of its affiliates' incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due to the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred as a result of the termination of any employees employed for our benefit by the departing general partner or its affiliates.

Transfer of General Partner Interest

At any time, our general partner may transfer all or any of its general partner interest to another person without the approval of our common unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in the General Partner

At any time, the owners of our general partner may sell or transfer all or part of its ownership interests in our general partner to an affiliate or third-party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

By transfer of incentive distribution rights in accordance with our partnership agreement, each transferee of incentive distribution rights will be admitted as a limited partner with respect to the incentive distribution rights transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;

- automatically becomes bound by the terms and conditions of our partnership agreement; and

- gives the consents, waivers and approvals contained in our partnership agreement.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of incentive distribution rights as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Incentive distribution rights are securities and any transfers are subject to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a limited partner for the transferred incentive distribution rights.

Until an incentive distribution right has been transferred on our books, we and the transfer agent may treat the record holder of the unit or right as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Sanchez Midstream Partners GP LLC as our general partner or from otherwise changing our management. Please read "—Withdrawal or Removal of Our General Partner" for a discussion of certain consequences of the removal of our general partner. If any person or group, other than our general partner and its affiliates, acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply in certain circumstances. Please read "—Meetings; Voting."

Limited Call Right

If at any time our general partner and its controlled affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign and transfer in whole or in part to any of its affiliates or beneficial owners or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons, as of a record date to be selected by our general partner, on at least 10, but not more than 60, days' notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the average of the daily closing prices of the partnership securities of such class over the 20 consecutive trading days preceding the date that is three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Possible Redemption of Ineligible Holders

Non-Taxpaying Holders; Redemption

To avoid any adverse effect on the maximum applicable rates chargeable to customers by us or any of our future subsidiaries, or in order to reverse an adverse determination that has occurred regarding such maximum rate, our partnership agreement provides our general partner the power to amend the agreement. If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us or our subsidiaries, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or appropriate to:

- obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of the federal income tax status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Citizen Assignees; Redemption

If our general partner, with the advice of counsel, determines that we are subject to U.S. federal, state or local laws or regulations that create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the nationality, citizenship or other related status of our limited partners (and their beneficial owners, to the extent relevant); and

- permit us to redeem the units held by any person whose nationality, citizenship or other related status creates substantial risk of cancellation or forfeiture of any property or who fails to comply with the procedures instituted by the general partner to obtain proof of the nationality, citizenship or other related status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on an applicable record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of our unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Interests." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates and purchasers specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding (other than any class of the Class C Preferred Units), that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. This loss of voting rights does not apply (i) to any person or group that acquires the units directly from our general partner or its affiliates, (ii) to any transferees of that person or group approved by our general partner, (iii) to any person or group who acquires the units with the specific prior approval of our general partner, (iv) Stonepeak with respect to its ownership (beneficial or recorded) of the Class C Preferred Units or (v) the holder of the 2019 Warrant with respect to the Junior Securities issued or issuable upon exercise of the 2019 Warrant. In addition, if any person or group beneficially owns 20% or more of any class of units solely as a result of actions taken by us, then the 20% threshold is increased, with respect to such person, to a percentage equal to such person's new beneficial ownership after the taking of such action plus the difference between 20% and such person's beneficial ownership prior to such action. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record common unitholders under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Voting Rights of Incentive Distribution Rights

If a majority of the incentive distribution rights are held by our general partner and its affiliates, the holders of the incentive distribution rights will have no right to vote in respect of such rights on any matter, unless otherwise required by law, and the holders of the incentive distribution rights shall be deemed to have approved any matter approved by our general partner.

If less than a majority of the incentive distribution rights are held by our general partner and its affiliates, the incentive distribution rights will be entitled to vote on all matters submitted to a vote of unitholders, other than amendments and other matters that our general partner determines do not adversely affect the holders of the incentive distribution rights in any material respect. On any matter in which the holders of incentive distribution rights are entitled to vote, such holders will vote together with the common units as a single class, and such incentive distribution rights shall be treated in all respects as common units when sending notices of a meeting of our limited partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our partnership agreement. The relative voting power of the holders of the incentive distribution rights and the common units will be set in the same proportion as cumulative cash distributions, if any, in respect of the incentive distribution rights for the four consecutive quarters prior to the record date for the vote bears to the cumulative cash distributions in respect of such class of units for such four quarters.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Except as described under "—Limited Liability," the common units and the Class C Preferred Units will be fully paid, and unitholders will not be required to make additional contributions.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a manager, managing member, general partner, director, officer, employee, agent, fiduciary or trustee of our partnership, our subsidiaries, our general partner, any departing general partner or any of their affiliates;
- any person who is or was serving at the request of a general partner, any departing general partner or any of their respective affiliates as a manager, managing member, general partner, director, officer, employee, agent, fiduciary or trustee of another person owing a fiduciary duty to us or our subsidiaries;
- any person who controls our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless our general partner otherwise agrees, it will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner and its affiliates for all direct and indirect expenses they incur or payments they make on our behalf and all other expenses allocable to us or otherwise incurred by our general partner and its affiliates in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses may include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. These books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of our common units, within 105 days after the close of each fiscal year, an annual report containing audited consolidated financial statements and a report on those consolidated financial statements by our independent registered public accounting firm. Except for our fourth quarter, we will also furnish or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website which we maintain.

We will furnish each record holder with information reasonably required for U.S. federal and state tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on their cooperation in supplying us with specific information. Every unitholder will receive information to assist him in determining his U.S. federal and state tax liability and in filing his U.S. federal and state income tax returns, regardless of whether he supplies us with the necessary information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;
- information as to the amount of cash, and a description and statement of the agreed value of any other capital contribution, contributed or to be contributed by each partner and the date on which each became a partner;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition (provided that obligation shall be satisfied to the extent the limited partner is furnished our most recent annual report and any subsequent quarterly or periodic reports required to be filed (or which would be required to be filed) with the SEC pursuant to Section 13(a) of the Exchange Act); and
- any other information regarding our affairs that our general partner determines is just and reasonable.

Under our partnership agreement, however, each of our limited partners and other persons who acquire interests in our partnership interests do not have rights to receive information from us or any of the persons we indemnify as described above under "—Indemnification" for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to our affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other limited partner interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

On November 22, 2016, we entered into a registration rights agreement with SN UR Holdings, LLC, and agreed to register the common units issued to such person on such date in connection with a private placement of our common units.

On August 2, 2019, we entered into an amended and restated registration rights agreement with Stonepeak and agreed to register the common units issuable to Stonepeak upon exercise of the 2019 Warrant.

DESCRIPTION OF 2019 WARRANT

On August 2, 2019, we issued the 2019 Warrant to Stonepeak. The 2019 Warrant entitles the holder to receive a number of each class of Junior Securities representing ten percent (10%) of the Junior Securities Deemed Outstanding (as defined in the 2019 Warrant) of such class as of the date the 2019 Warrant is exercised.

The 2019 Warrant is exercisable until the later of August 2, 2026 or the thirtieth (30th) calendar day following the date on which all of the Class C Preferred Units are redeemed by us. There is no exercise price payable in connection with the exercise of the 2019 Warrant. As a result of the 2019 Warrant having no exercise price, the 2019 Warrant does not contain any provisions for changes to or adjustments in the exercise price.

In the event of any (i) capital reorganization of the Partnership, (ii) reclassification of Partnership interests (other than a change as a result of a unit dividend or subdivision, split-up or combination of units), (iii) consolidation or merger of the Partnership with or into another Person, (iv) sale of all or substantially all of the Partnership's assets to another Person or (v) other similar transaction, in each case which entitles the holders of Junior Securities other than Excluded Junior Securities (as defined in the 2019 Warrant) to receive (either directly or upon subsequent liquidation) units, securities or assets with respect to or in exchange for such class of Junior Securities (each such transaction, an "Adjustment Transaction"), the 2019 Warrant shall, immediately after such Adjustment Transaction, remain outstanding and shall thereafter, in lieu of or in addition to (as the case may be) the number of Warrant Units (as defined in the 2019 Warrant) then exercisable under the 2019 Warrant, be exercisable for the kind and number of units or other securities or assets of the Partnership or of the successor Person resulting from such transaction to which the holder would have been entitled upon such Adjustment Transaction if the Holder had exercised the 2019 Warrant in full immediately prior to the time of such Adjustment Transaction and acquired the applicable number of Warrant Units then issuable hereunder as a result of such exercise.

Exhibit 10.12

Executive Officer Compensation

Base Salary

The following table sets forth the base salary for each named executive officer of Sanchez Midstream Partners GP LLC, the general partner of Sanchez Midstream Partners LP (the "Partnership"). Each person is an employee of Sanchez Oil & Gas Corporation ("SOG") and provides services to the Partnership, with the amounts listed being the portion of the salary allocated to the Partnership, effective as of January 1, 2020.

Sanchez Production Partners LP, Officer	**Base Salary**
Gerald F. Willinger *Chief Executive Officer*	$600,000
Charles C. Ward *Chief Financial Officer & Secretary*	$375,000
Patricio D. Sanchez *President & Chief Operating Officer*	$400,000

Other Benefits

SOG does not maintain a defined benefit pension plan for its employees because it believes that such plans primarily reward longevity rather than performance. SOG provides a basic benefits package generally to all employees, which includes a 401(k) plan, parking costs, and health, disability and life insurance. In addition, SOG, in its discretion, may permit executive officers to utilize company-owned or chartered aircraft for personal use. In its discretion, SOG and/or the board of directors of the Partnership's general partner may award the named executive officers cash bonuses and/or equity compensation.

Exhibit 10.13

Board Compensation for Directors*

Type of Compensation	Amount
Board Cash Retainer++	Fiscal 2020: $35,000, payable quarterly on the last day of each fiscal quarter, commencing January 1, 2020+
	Fiscal 2021: $10,000, payable quarterly on the last day of each fiscal quarter, commencing January 1, 2020+
Equity Grant++	Fiscal 2020: no equity grant included in compensation for directors.
	Fiscal 2021: $100,000 (issued March 31 of each year based on the Partnership's Common Unit closing price on the NYSE American on such date (or the next trading day if such date is not a trading day)); fully vested upon issuance; any person appointed to the Board shall be issued equity on a pro rata basis from the date of appointment through the following March 31 (with the number of Common Units based on the closing price on the NYSE American on the date of appointment (or the next trading day if such date is not a trading day)).
Board Meeting Fees	$1,500 for each meeting attended
Committee Meeting Fees	$1,000 for each substantive meeting of the Audit Committee attended
	$3,500 for each substantive meeting of the Conflicts Committee attended
Committee Chair Retainer	$3,500 for Audit Committee Chair, payable quarterly on the last day of each fiscal quarter+
	$2,500 for Conflicts Committee Chair, payable quarterly on the last day of each fiscal quarter+
Other Benefits	Independent Directors are eligible to participate in the basic health benefits package available to SOG employees. Additionally, the Independent Directors are eligible for life and accidental death and dismemberment insurance.

* Includes all persons serving as directors, excepting those appointed by the Class C Preferred Holders, Officers and those with ownership interests in SP Holdings, LLC.

\+ For any person who ceases to serve during the fiscal quarter prior to such payment date, such person shall receive a pro rata amount for the portion of the fiscal quarter so served.

++ During Fiscal 2020, in recognition of the depressed price of the Partnership's Common Units and the corresponding dilutive effect of any equity grant, no equity grant shall occur. As a result, the Board Cash Retainer shall increase by an annual amount equal to $100,000, or $25,000 per fiscal quarter.

Exhibit 21.1

List of Subsidiaries of Sanchez Midstream Partners LP

Name	Jurisdiction of Organization
SEP Holdings IV, LLC	Delaware
Catarina Midstream, LLC	Delaware
SECO Pipeline, LLC	Delaware

* The names of certain indirectly owned subsidiaries have been omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary pursuant to Rule 1-02(W) of Regulation S-X.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

To the Board of Directors
Sanchez Midstream Partners GP LLC:

We consent to the incorporation by reference in the registration statements (Nos. 333-202578, 333-210783, 333-217007 and 333-230273) on Form S-8, and (Nos. 333-217003, 333-218570 and 333-223569) on Form S-3 of Sanchez Midstream Partners LP of our report dated March 13, 2020, with respect to the consolidated balance sheets of Sanchez Midstream Partners LP as of December 31, 2019 and 2018, and the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2019, and the related notes, which report appears in the Annual Report on Form 10-K for the year ended December 31, 2019 of Sanchez Midstream Partners LP.

/s/ KPMG LLP

Houston, Texas
March 13, 2020

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm in the Annual Report on Form 10-K for the year ended December 31, 2019 of Sanchez Midstream Partners LP (the "Form 10-K") and to the inclusion of our report, dated March 2, 2020, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of Sanchez Midstream Partners LP as of December 31, 2019, in the Form 10-K and/or as an exhibit to the Form 10-K.

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-202578, 333-210783, 333-217007 and 333-230273), and Form S-3 (Nos. 333-217003, 333-218570 and 333-223569) of Sanchez Midstream Partners LP, including any amendments thereto, of such information.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 13, 2020

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

Exhibit 31.1

SANCHEZ MIDSTREAM PARTNERS LP
CERTIFICATION

I, Gerald F. Willinger, certify that:

1. I have reviewed this annual report on Form 10-K 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 fiscal 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:

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: March 13, 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 annual report on Form 10-K 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 fiscal 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:

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: March 13, 2020

/s/ CHARLES C. WARD
Charles C. Ward
Chief Financial Officer and Secretary
Sanchez Midstream Partners GP, LLC, the 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**

In connection with the accompanying annual report of Sanchez Midstream Partners LP (the "Partnership") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Gerald F. Willinger, Chief Executive Officer of Sanchez Midstream Partners GP LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: March 13, 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 32.2

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

In connection with the accompanying annual report of Sanchez Midstream Partners LP (the "Partnership") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charles C. Ward, Chief Financial Officer and Secretary of Sanchez Midstream Partners GP LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: March 13, 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)

SANCHEZ MIDSTREAM PARTNERS LP

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2019

/s/ Eric T. Nelson	/s/ Keith L. Woodroome
Eric T. Nelson, P.E.	Keith L. Woodrome, P.E.
TBPE License No. 102286	TBPE License No. 110424
Managing Senior Vice President	Vice President
[SEAL]	[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

March 2, 2020

Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Sanchez Midstream Partners LP (SNMP) as of December 31, 2019. The subject properties are located in the states of Louisiana and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 12, 2020 and presented herein, was prepared for public disclosure by SNMP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of SNMP as of December 31, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

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SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Sanchez Midstream Partners LP
As of December 31, 2019

	Proved		
	Developed		Total
	Producing	Non-Producing	Proved
Net Reserves			
Oil/Condensate – Mbbl	2,220	21	2,241
Plant Products – Mbbl	405	5	410
Gas – MMcf	2,063	26	2,089
MBOE	2,969	30	2,999
Income Data ($M)			
Future Gross Revenue	$ 136,238	$ 1,364	$ 137,602
Deductions	75,450	931	76,381
Future Net Income (FNI)	$ 60,788	$ 433	$ 61,221
Discounted FNI @ 10%	$ 38,049	$ 300	$ 38,349

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousands of barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of SNMP. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one-line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, workover costs, recompletion costs, oil and natural gas gathering, marketing and transportation costs, and certain abandonment costs net of salvage. The "Other" costs shown in the cash flow projections are the variable portion of direct operating costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 96 percent and gas reserves account for the remaining four percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2019 Total Proved
8	$41,500
9	$39,862
12	$35,656
15	$32,290

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

The proved shut-in reserves included in this report are attributable to wells that are currently awaiting mechanical, pipeline, or field operations that will allow the well to produce at economic rates. These operations may include artificial lift optimization/installation, pipeline remediation, and workovers such as tubing and casing leak repairs and cleanouts.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At SNMP's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

SNMP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing**,** the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which SNMP owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

All of the proved producing, shut-in, and behind pipe reserves attributable to producing, shut-in, and behind pipe wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through October 2019 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by SNMP or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

SNMP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by SNMP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, workover and recompletion costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, and adjustments or differentials to product prices. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by SNMP. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to

Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by SNMP. Wells that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

SNMP furnished us with the above mentioned average prices in effect on December 31, 2019. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by SNMP. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SNMP to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$55.69/bbl	$59.55/bbl
	NGLs	Mt. Belvieu - Propane	$23.13/bbl	$13.68/bbl
	Gas	Henry Hub	$2.58/MMBTU	$2.66/Mcf

The term MMBTU denotes millions of British thermal units.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by SNMP and are based on the operating expense reports of SNMP and include only those costs directly applicable to the leases or wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by SNMP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by SNMP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by SNMP were accepted without independent verification.

The proved developed non-producing reserves in this report have been incorporated herein in accordance with SNMP's plans to develop these reserves as of December 31, 2019. The implementation of SNMP's development plans as presented to us and incorporated herein is subject to the approval process adopted by SNMP's management. As the result of our inquiries during the course of preparing this report, SNMP has informed us that the development activities included herein have been subjected to and received the internal approvals required by SNMP's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to SNMP. Additionally, SNMP has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by SNMP were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Sanchez Midstream Partners LP. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Sanchez Midstream Partners LP.

SNMP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, SNMP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of SNMP, of the references to our name, as well as to the references to our third party report for SNMP, which appears in the December 31, 2019 annual report on Form 10-K of SNMP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by SNMP.

We have provided SNMP with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by SNMP and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPE License No. 102286
Managing Senior Vice President **[SEAL]**

/s/ Keith L. Woodrome

Keith L. Woodrome, P.E.
TBPE License No. 110424
Vice **[SEAL]**
President

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is a Managing Senior Vice President and a member of the Board of Directors. He is responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Nelson served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Nelson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Nelson earned a Bachelor of Science degree in Chemical Engineering from the University of Tulsa in 2002 (summa cum laude) and a Master of Business Administration from the University of Texas in 2007 (Dean's Award). He is a licensed Professional Engineer in the State of Texas. Mr. Nelson is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Nelson fulfills. As part of his 2019 continuing education hours, Mr. Nelson attended over 17 hours of training during 2019 covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, evaluations of resource play reserves, evaluation of simulation models, procedures and software, and ethics training.

Based on his educational background, professional training and more than 14 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Nelson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) *Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.