Sanchez Midstream Partners LP
Form 10-K
March 07, 2019

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, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 001-33147

Sanchez Midstream Partners LP

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (713) 783-8000

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

Title of each class	Name of each exchange on which registered
Common Units representing Limited Partner Interests	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Aggregate market value of Sanchez Midstream Partners LP Common Units, without par value, held by non-affiliates as of June 30, 2018 was approximately $128,395,151 based upon the NYSE American closing price.

Common Units outstanding on March 7, 2019: 17,464,315 common units.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

All of these types of statements, other than statements of historical fact included in this Form 10-K, are forward-looking statements. 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," "t 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 our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe that such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate.

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

- our ability to successfully execute our business, acquisition and financing strategies;
- the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements;
- the credit worthiness and performance of our counterparties, including financial institutions, operating partners, customers and other counterparties;
- our ability to make, maintain and grow distributions;
- the ability of our partners to perform under our joint ventures and partnerships;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;

- our ability to utilize the services, personnel and other assets of the sole member of our general partner, SP Holdings, LLC (“Manager”), pursuant to the Services Agreement (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;

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- 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;

- the effectiveness of our internal control over financial reporting;

- 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 the forward-looking statements due to factors listed in the "Risk Factors" section and elsewhere in this Form 10-K. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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COMMONLY USED DEFINED TERMS

As used in this 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.
- “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: SNEC) and its consolidated subsidiaries.
- “SOG” refers to Sanchez Oil & Gas Corporation, an entity that provides operational support to us.
- “SP Holdings” or “Manager” refers to SP Holdings, LLC, the sole member of our general partner.

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PART I

Item 1.Business
Overview

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. We have ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, all located in the Western Eagle Ford in South Texas. 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. 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."

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 and will continue to provide significant growth opportunities. As of March 7, 2019, Sanchez Energy owned approximately 13.0% 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.

In addition to being the sole member of our general partner, Manager 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 strategies.

Business Strategy

Our primary business objective is to create long-term value by generating stable and predictable cash flows that allow us to make 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 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.

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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, 2018 and 2017. 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 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 “Sanchez Energy’s Catarina Asset” and the western portion of such net acreage “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 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 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 Transwestern Pipeline Company, LLC.

In conjunction with the acquisition of Western Catarina Midstream, 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 the incremental infrastructure fee on a month-to-month basis.

During the year ended December 31, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.8 MBbls/d of oil, 157.2 MMcf/d of natural gas and 11.0 MBbls/d of water. The average age of the Western Catarina Midstream assets is approximately eight years, and have an average expected life of approximately 22 additional years.

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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 Comanche acres in the Western Eagle Ford pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche 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 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 gathering and processing 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 continues on a month-to-month basis until terminated by either party. During the year ended December 31, 2018, Sanchez Energy transported average daily production through Seco Pipeline of approximately 35.4 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, 2018, were approximately 3.5 MMBoe, all of which were classified as proved developed, with 13% being natural gas, 15% being NGLs, and 72% being oil. At December 31, 2018, we owned approximately 48 net producing wells. Our total average proved reserve-to-production ratio is approximately 9 years and our portfolio decline rate is 11% to 20% based on our estimated proved reserves at December 31, 2018.

Below is a description of our operations and our oil and natural gas properties by basin at December 31, 2018:

Locations

Of our reserves, 98% were located in the Eagle Ford Shale on non-operated properties, where production during the year ended December 31, 2018 was 381.8 MBoe and approximately 3,394.5 MBoe of estimated proved reserves were held at December 31, 2018. All of these reserves were classified as proved developed, with 13% being natural gas, 16% being NGLs, and 71% being oil.

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The remaining reserves were located on non-operated properties in Louisiana. During the year ended December 31, 2018, production on Louisiana properties was 3.1 MBoe, and approximately 57.7 MBoe of estimated proved reserves were held at December 31, 2018, 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 SOG and Marathon Oil Company and the Louisiana properties are operated by SOG.

Production 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 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 (the “Briggs Divestiture”). In addition, other than limited obligations retained by us, 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. The divestitures were all closed by May 8, 2018 and we recorded a total gain of approximately $1.1 million on the sale.

Texas Production Divestiture

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

Non-Operated Production Divestiture

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

Oklahoma Production Divestiture

In May 2017, we entered into a purchase and sale agreement to sell all of our equity interests in the entities that owned our remaining Oklahoma production assets for cash consideration of $5.5 million, and assumption by the buyer of all obligations relating to the assets arising after the closing date and all plugging and abandonment costs relating to the

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assets arising prior to the closing date (the "Oklahoma Production Divestiture"). The Oklahoma Production Divestiture closed July 17, 2017 and we recorded a gain of $2.4 million on the sale.

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:	2018	2017
Estimated proved reserves:		
Oil (MMBbl)	2.5	3.3
Natural gas (MMcf)	2.7	6.7
NGLs (MMBbl)	0.5	0.9
Total proved reserves (MMBoe)	3.5	5.3
Estimated proved developed reserves:		
Oil (MMBbl)	2.5	3.3
Natural gas (MMcf)	2.7	6.7
NGLs (MMBbl)	0.5	0.9
Total proved developed reserves (MMBoe)	3.5	5.3
Proved developed reserves as a percent of total reserves	100%	100%
Standardized measure ($ in millions)	$ 52.2	$ 56.7

(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 2018 estimates of total proved reserves decreased 1.8 MMBoe from 2017 primarily due to divestitures totaling approximately 1.1 MMBoe.

As of December 31, 2018, we have 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, 2019.

At December 31, 2018 and December 31, 2017, Ryder Scott Co. LP ("Ryder Scott"), an independent oil and natural gas engineering firm, prepared estimates of all our proved reserves. We used Ryder Scott's 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 Ryder Scott’s 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.

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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, 2018	2017	Variance		
Net production:					
Natural gas (MMcf)	434	2,521	(2,087)	(83)	%
Oil production (MBbl)	296	414	(118)	(29)	%
NGLs (MBbl)	71	102	(31)	(30)	%
Total production (MBoe)	439	936	(497)	(53)	%
Average daily production (Boe/d)	1,203	2,565	(1,362)	(53)	%
Average sales prices:					
Natural gas price per Mcf with hedge settlements	$ 2.30	$ 3.48	$ (1.18)	(34)	%
Natural gas price per Mcf without hedge settlements	$ 2.39	$ 2.40	$ (0.01)	(0)	%
Oil price per Bbl with hedge settlements	$ 62.64	$ 64.83	$ (2.19)	(3)	%
Oil price per Bbl without hedge settlements	$ 67.14	$ 49.32	$ 17.82	36	%
NGL price per Bbl without hedge settlements	$ 24.07	$ 19.58	$ 4.49	23	%
Total price per Boe with hedge settlements	$ 48.41	$ 40.19	$ 8.22	20	%
Total price per Boe without hedge settlements	$ 51.52	$ 30.41	$ 21.11	69	%
Average unit costs per Boe:					
Field operating expenses (a)	$ 17.82	$ 14.47	$ 3.35	23	%
Lease operating expenses	$ 15.31	$ 12.89	$ 2.42	19	%
Production taxes	$ 2.51	$ 1.58	$ 0.93	59	%
Depreciation, depletion and amortization	$ 10.93	$ 10.17	$ 0.76	7	%

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

Existing Wells

The following table sets forth information at December 31, 2018, 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	Net	Oil Gross	Net
Operated	—	—	—	—
Non-operated	—	—	91	48
Total	—	—	91	48

We did not convert any proved undeveloped wells into proved producing wells in 2018.

Drilling Activity

With respect to oil and natural gas wells drilled and completed during the years ended December 31, 2018 and 2017, 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, 2018 or 2017. During the year ended December 31, 2018, there were no wells drilled either gross or net,

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and there were no wells in progress. During the year ended December 31, 2017, one gross well, or approximately 0.2 net wells, was drilled.

Developed and Undeveloped Acreage

The following table sets forth information related to our leasehold acreage as of December 31, 2018.

	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 stem from wellbore rights only. We have a small lease position of less than 1,000 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 71% and 63% of our total revenue for the years ended December 31, 2018 and 2017, 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.”

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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

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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 greenhouse gases ("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 0000a 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

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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.

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.

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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 a HCA;
- 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

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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 a HCA. 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. PHMSA has not yet finalized these proposed regulations. 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-

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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, 2018, 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 7, 2019, 6 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

We are headquartered in Houston, Texas.

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.

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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 Financing and Credit Environment;
- Risks Related to Our Cash Distributions;
- Risks Related to Regulatory Compliance;
- Risks Related to an Investment in Us and Our Common Units; and
- Tax Risks.

Risks Related to Our Midstream Business

Because the majority of our total revenue in general and substantially all of our revenue relating to the operation of our midstream business is derived from Sanchez Energy, any development that materially and adversely affects Sanchez Energy’s operations, financial condition or market reputation could have a material and adverse impact on us.

Sanchez Energy is our most significant customer and accounted for approximately 71% of our total revenue and substantially all of our midstream business revenue for the year ended December 31, 2018. We are dependent on Sanchez Energy as our only current customer for utilization of Western Catarina Midstream. In addition, Sanchez Energy is the primary customer for utilization of the Carnero Gathering Line, the Raptor Gas Processing Facility and the Seco Pipeline. We expect that a majority of revenues relating to these assets will be derived from Sanchez Energy for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Sanchez Energy’s production, drilling and completion schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Sanchez Energy, including, among others:

- a reduction in or slowing of Sanchez Energy’s development program, especially on Sanchez Energy’s Catarina Asset, which would directly and adversely impact demand for our gathering and processing services;
- a decline in the price of natural gas, NGLs or oil, which have been extremely volatile for over two years and have recently declined rapidly;
- Sanchez Energy’s ability to finance its operations and development activities;

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- the availability of capital on an economic basis to fund Sanchez Energy's exploration and development activities;
- Sanchez Energy's ability to replace reserves;
- Sanchez Energy's drilling and operating risks, including potential environmental liabilities;
- Sanchez Energy's retention and operation of its current assets, including Sanchez Energy's Catarina Asset and Comanche asset;
- the speculative nature of drilling wells;
- transportation capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation.

A reduction in the price of natural gas, NGLs or oil could cause Sanchez Energy to record oil and natural gas property impairments, which would adversely affect its future business and development. Sanchez Energy utilizes the successful efforts method of accounting to account for its oil and natural gas exploration and development activities. Under this method of accounting, a company is required when facts and circumstances indicate that the carrying value may not be recoverable to determine whether the book value of its oil and natural gas properties (excluding unevaluated properties) is less than or equal to the estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. For the year ended December 31, 2018, Sanchez Energy recorded $6.6 million in proved property impairments. Sanchez Energy could incur additional non-cash impairments to its proved oil and natural gas properties in 2019 if the price of natural gas, NGLs or oil declines. These impairments, along with a substantial and sustained decline in oil and natural gas prices, may materially and adversely affect its future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We are subject to the risk of non-payment or non-performance by Sanchez Energy, including with respect to the Gathering Agreement and the Seco Pipeline Transportation Agreement. During 2018, Sanchez Energy's stock price declined significantly from a high closing price of $5.99 per share on January 12, 2018 to a low closing price of $0.25 per share on December 27, 2018. In October 2018, Sanchez Energy announced the appointment of two board members with considerable experience in the areas of turnaround management and financial restructuring. In November 2018, Moody's Investors Service downgraded Sanchez Energy's corporate family rating from B3 to Caa1. In addition, in December of 2018, Sanchez Energy announced that it had engaged Moelis & Company LLC as a financial advisor to explore strategic alternatives to strengthen its balance sheet and maximize the value of the company. In February 2018, trading in Sanchez Energy's common stock was suspended on the NYSE and the NYSE notified Sanchez Energy that it's common stock is subject to delisting proceedings. We cannot predict the extent to which Sanchez Energy's business or relationship with us would be impacted from a NYSE delisting, failure to implement a viable strategic alternative or if conditions in the energy industry were to further deteriorate, nor can we estimate the impact that such events would have on Sanchez Energy's ability to execute its drilling and development program or perform under its various commercial agreements with us, but such events could have materially adverse consequences. Any material non-payment or non-performance by Sanchez Energy would reduce our ability to make distributions to our unitholders.

In addition, due to our relationship with Sanchez Energy, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any further impairment to Sanchez Energy's financial condition or its credit ratings.

Any material limitation on our ability to access capital as a result of such adverse changes at Sanchez Energy could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, we believe the material adverse changes at Sanchez Energy have negatively impacted our unit price

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and could continue to do so, limiting our ability to raise capital through equity issuances or debt financing, and may negatively affect our ability to engage in, expand or pursue our business activities, and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

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). In addition, Sanchez has various continuous drilling commitments under the leases covering the Comanche asset. If Sanchez Energy fails to meet these minimum drilling commitments, 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

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development activity result in our inability to maintain the current levels of throughput on our facilities, those reductions could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

The Gathering Agreement contains provisions that can reduce the cash flow stability 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, NGLs and oil 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, NGLs and oil 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, 2018, total excess oil and gas volumes from Sanchez Energy have shortened the primary terms of the volume commitments by 279 and 222 days respectively.

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, which could be in as early as four years.

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 make cash distributions to our unitholders.

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 our unitholders.

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 flows available for distribution to our unitholders. 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;

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- 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 make cash distributions to our unitholders.

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. The increased levels of production in the Eagle Ford Shale may result in a shortage of equipment and skilled labor. 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 distributions.

We received approximately $24.9 million in cash from the Carnero JV in the form of distributions during the year ended December 31, 2018. 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 distributions to our unitholders.

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

In 2016, we purchased from Sanchez Energy a 50% equity interest in each of Carnero Gathering and Carnero Processing, each a joint venture that is 50% owned by Targa and operated by Targa. 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 Comanche acres in the Western Eagle Ford 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 our unitholders.

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

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

We do not own the land on which Western Catarina Midstream 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. 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 make cash distributions to our unitholders.

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.

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 highly dependent on 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. We process transactions on a daily basis and rely upon the proper functioning of computer systems. 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.

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Additionally, we rely on information systems across our operations, including the management of processes and transactions. A disrupt 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.

These systems could be damaged or interrupted by a security breach, cyber-attack, fire, flood, power loss, telecommunications failure or similar event. Further, our business interruption insurance may not compensate us adequately for losses that may occur. Additionally, federal legislation relating to cybersecurity threats could impose additional requirements on our operations. Finally, our implementation of additional procedures and controls in response to such legislation or to otherwise monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs.

Risks Related to Our Production Business

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

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

- domestic and foreign supply of and demand for oil, natural gas and NGLs;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in countries producing oil, natural gas and NGLs, 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 oil, natural gas and NGLs;
- 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 oil, natural gas and NGLs;
- the availability of refining capacity; and
- the price and availability of, and consumer demand for, alternative fuels.

Governmental actions may also affect prices for oil, natural gas and NGLs. In the past, prices for oil, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. Beginning in the latter half of 2014, oil prices declined precipitously, and continued to decline throughout 2015 as well as the start 2016. Although oil prices rebounded in 2017, they declined again in the second half of 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

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net cash flows of our net estimated proved reserves. For the year ended December 31, 2018, we did not record impairment on our oil and natural gas properties. During the same period in 2017, our non-cash impairment charges were approximately $4.7 million, to impair certain of our oil and natural gas properties in Texas.

In addition, our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGLs, 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 oil, natural gas and NGLs would reduce the amount of oil, natural gas and NGLs that we can economically produce;
- reduce the amount of cash flow 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 oil, natural gas and NGLs.

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 distributions to our unitholders.

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;

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- 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 operation.

Any of these events can cause increased 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.

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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 distributions to our unitholders.

Future price declines or downward reserve revisions may result in additional 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 make cash distributions to our unitholders.

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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 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 distributions.

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 distributions to our unitholders.

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

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natural gas industry. Our inability to compete effectively with other companies could have a material adverse effect on our business activities, 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 March 31, 2020. 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

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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 March 31, 2020. 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.

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 make 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 and, as a result, we will be unable to maintain or increase our future cash distributions. 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 to our unitholders. 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 limit our ability to pay distributions to our 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 maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the prevailing distribution rate. 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 may restrict us from paying any distributions on our outstanding units.

We have the ability to pay distributions to unitholders under our Credit Agreement from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distribution to unitholders may be made if the borrowings outstanding, net of available cash, under our Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. We have obtained waivers of the Credit Agreement limitation in the past and may need to do so in the future. Our available cash is reduced by any cash reserves established by the Board for the proper conduct of our business and the payment of fees and expenses. Our ability to pay distributions to our unitholders in any quarter will be solely dependent on our ability to generate sufficient cash from our operations and is subject to the approval of the Board.

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 distributions to our unitholders.

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 distributions could be affected.

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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. 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 distributions.

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 distributions to unitholders; 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 any distributions, 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 future expected production volumes, 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 any temporary or long-term 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, ability to pay distributions and the market price of our common 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 distribution to unitholders.

The provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the rules adopted thereunder and other regulations, including EMIR, may adversely affect our ability to hedge risks associated with our business, which may impact our results of operations and cash flows.

The swaps regulatory provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") and the rules of the Commodity Futures Trading Commission ("CFTC") thereunder now in effect and adopted by the CFTC in the future may adversely affect our ability to manage certain of our risks on a cost effective basis. As mandated by the Dodd-Frank Act, the CFTC has proposed rules to set limits on the positions market participants may hold in certain core futures and futures equivalent contracts, option contracts or swaps for or linked to certain physical commodities, including certain oil and natural gas, subject to exceptions for certain bona fide hedging and other types of transactions. If the position limits in the proposed rules or other similar position limits are imposed, our ability to execute our hedging strategies described above could be compromised.

Under the provisions of the Dodd-Frank Act and rules adopted thereunder, we may have to clear on a designated clearing organization and execute on certain markets any swap that we enter into that falls within a class of swaps designated by the CFTC for mandatory clearing unless we qualify for an exception from such requirements as to such swap. The CFTC has designated six classes of interest rate swaps and credit default swaps for mandatory clearing, but has not yet proposed rules designating any class of physical commodity swaps or other class of swaps for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for the swaps that we enter into to hedge our commercial risks, if we were to fail to qualify for that exception as to a swap we enter into and were required to clear that swap, we would have to post margin with respect to such swap, our cost of entering into and maintaining such swap could increase and we would have less flexibility with respect to that swap than we would enjoy were the swap not cleared. Moreover, the application of the mandatory clearing and trade execution requirements and other swap regulations to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

As required by the Dodd-Frank Act, the CFTC and the federal banking regulators have adopted rules requiring certain market participants to collect initial and variation margin with respect to uncleared swaps from their counterparties except as to any uncleared swaps as to which the counterparty qualifies for the end user exception from the mandatory clearing exception. Although those rules do not require initial margin to be collected from non-financial end users of uncleared swaps, an affected market participant must collect from its counterparty to any uncleared swap that is a non-financial end user, but that does not qualify for the end user exception with respect to that uncleared swap, variation margin with respect to that swap at those times and in those forms and amounts as the market participant determines appropriately addresses the credit risk posed by that counterparty and the risk of that swap. The requirements of those rules relating to initial margin are being phased through September 1, 2020. Were we not to qualify for the end user exception as to any of our uncleared swaps and otherwise have to post initial or variation margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would increase. In addition, our counterparties that are subject to the regulations imposing the Basel III capital requirements on them may increase the cost to us of entering into swaps with them or contractually require us to post collateral or greater amounts of collateral with them in connection with such swaps to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets.

The European Market Infrastructure Regulation ("EMIR") includes regulations related to the trading, reporting, clearing of derivatives and providing margin with respect to derivatives. EMIR may result in increased costs for OTC derivative counterparties and also lead to an increase in the costs of, and demand for, the liquid collateral with respect to any swap to which we are a party and that is governed by EMIR. Therefore, EMIR may impact our ability to maintain or enter into derivatives with certain of our European counterparties.

The Dodd-Frank Act's swaps regulatory provisions, the related rules described above and the record keeping, reporting and business conduct rules imposed by the Dodd-Frank Act on other swaps market participants, as well as EMIR and the regulations imposing the Basel III capital requirements on certain swaps market participants, could significantly increase the cost of derivative contracts (including through requirements to post margin or other collateral, which could

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adversely affect our available liquidity), materially alter the terms of the derivative contracts that we enter into, particularly the provisions relating to the our need to provide margin with respect to, or collateralize our obligations under such derivative contracts, reduce the availability of derivatives to protect against certain risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and to execute our hedging strategies. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our results of operations and cash flows may become more volatile and could be adversely affected.

Risks Related to Our Distributions to Unitholders

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

Our ability to increase our distributions depends 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 distributions to unitholders 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. Ultimately, the amount of available cash that we may distribute to our unitholders 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 facilities;
- the amount of oil and natural gas 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;

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- 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, including the maintenance of our asset base and the payment of future distributions on our common units and incentive distribution rights; and
- the level of our maintenance capital expenditures.

As a result of these factors, we may not have sufficient available cash to maintain or increase our quarterly distributions. 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 and may be significantly less than any prior distributions that we have previously made. If we do not have sufficient available cash or operating cash flows to maintain or increase quarterly distributions, the market price of our common units may decline substantially.

In order for us to make a distribution from available cash under our Credit Agreement, our outstanding debt balances, net of available cash, must be less than 90% of our borrowing base, as determined by our lenders, after giving effect to the proposed distribution. We have obtained waivers of the Credit Agreement limitation in the past and may need to do so in the future. Our available cash excludes any cash reserves established by the Board for the proper conduct of our business and the payment of fees and expenses. We are subject to additional future borrowing base redeterminations before our Credit Agreement matures in March 2020 and cannot forecast the level at which our lenders will set our future borrowing base. If our lenders reduce our borrowing base because of any of the numerous factors generally described in this caption “Risk Factors,” our outstanding debt balances, net of available cash, may exceed 90% of the borrowing base, as determined by our lenders, and we may be unable to make quarterly distributions.

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

The amount of cash that we have available for distribution depends primarily on 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 distributions even when we record net income, and we may pay 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 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;

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- 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. If we raise our distribution level in response to increased operating cash flows during periods of relatively high commodity prices, we may not be able to sustain those distribution levels during periods of lower commodity price levels.

Our operations require capital expenditures, which will reduce any cash available for distribution to our unitholders.

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 reduce the amount of cash that we may have available for distribution to our unitholders. In addition, our actual capital expenditures will vary from quarter to quarter.

Each quarter we are required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available for distribution to unitholders 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 to unitholders 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. Over time, if we do

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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 distributions in full, if at all.

Our hedging activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay 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 up to five years. 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.

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

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;

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- 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 distributions.

Inadequate insurance could have a material adverse impact on our business, financial condition, results of operations and ability to pay distributions to our unitholders.

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, results of operations and ability to pay distributions to our unitholders.

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 distributions to our unitholders 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.

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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.

Sanchez Energy 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 or Sanchez Energy. 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.

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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.

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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 to our unitholders.
- 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 to our unitholders.
- 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.

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· 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 Holdings LLC will expire on March 31, 2019.

In connection with our October 2015 issuance of Class B Preferred Units to Stonepeak Catarina Holdings LLC (“Stonepeak Catarina”), an affiliate of Stonepeak Infrastructure Partners (“Stonepeak”), we entered into that certain 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 B Preferred Units, agreed that it and its affiliates would refrain from, among other things, (i) acquiring beneficial ownership of additional common units, Class A Preferred Units, Class B Preferred Units or other Partnership Interests (as defined in our partnership agreement); (ii) acquiring any of our debt or assets, or the debt or assets of any 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, joint venture, acquisition or similar transaction involving us or our general partner or any of our respective affiliates or properties

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(excluding Sanchez Energy and its subsidiaries and its and their 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) 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, and (ix) if Sanchez Midstream Partners GP LLC is removed as our general partner, then the participation 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 (actions described in the foregoing (i) through (ix), the "Standstill Actions"). Under the terms of the Representation and Standstill Agreement, the prohibition against taking any of the Standstill Actions expires on March 31, 2019. While we are not aware of any current intentions by Stonepeak Catarina or its affiliates to take any of the Standstill Actions, we will no longer be afforded protection from such actions after March 31, 2019. If any of the Standstill Actions occurs it may materially and adversely affect our business, liquidity, cash flows and prospects.

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.

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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 level of our quarterly distributions;
- 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 holders of our common units 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

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(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.

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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 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 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 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, 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.

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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.

Following the conversion of the Class B Preferred Units, you may experience dilution of your common units and we may not have sufficient available cash to enable us to maintain or increase the quarterly distribution amount on our common units.

As of March 7, 2019, there were 31,310,896 Class B Preferred Units issued and outstanding which are convertible at any time into not less than 31,310,896 common units (plus additional common units resulting from the issuance of paid-in-kind distributions, if any, on such Class B Preferred Units). Any future conversion of the Class B Preferred Units would dilute the percentage ownership held by our common unitholders. Additionally, any future conversion of Class B Preferred Units will result in the payment of distributions on any additional common units issued as a result of such conversion, and we may not have sufficient available cash to maintain or increase the quarterly distribution amount on our common units following the payment of such distributions.

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.

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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

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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 in the anticipated cash flow 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.

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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. We are unable to predict whether any of these changes or other 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 and 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 common unitholders may 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 to our unitholders 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 to our unitholders 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 to our unitholders 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.

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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 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 temporarily 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. Our counsel is unable to opine as to the validity of such filing positions. 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.

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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, such tax items must be prorated on a daily basis and these regulations do not specifically authorize all aspects of our proration method. Accordingly, our counsel is unable to opine as to the validity of this 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. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to effect a short sale of common units; therefore, our 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 borrowing 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 must 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.

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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. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

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

We are the subject of legal proceedings and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such legal proceedings and claims. While the legal proceedings and claims are asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that these matters will have a material adverse effect on our financial position or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

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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 59 on March 7, 2019, 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, 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:

- 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.
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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

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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 Revised Uniform Limited Partnership Act (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 cash flow shortfalls 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.
- As long as our Class B Preferred Units remain outstanding, our ability to make distributions to common unitholders is prohibited unless our available cash less working capital borrowings during or subsequent to the quarter is at least 1.65 times the amount of the Class B Preferred Unit distribution for such quarter.

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.

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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, 2018.

Unregistered Sales of Securities

In connection with providing services under the Services Agreement for the year ended December 31, 2018, the Partnership issued 989,544 common units to Manager. See Note 14 "Related Party Transactions" 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(2) thereof as a transaction by an issuer not involving a public offering.

Issuer Purchases of Equity Securities

No common units were repurchased by us during the fourth-quarter 2018.

Default Upon Senior Securities

There were no defaults on senior securities for the years ended December 31, 2018 or 2017.

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.

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Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following information should be read in conjunction with the accompanying financial statements and related notes included elsewhere in 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” and the risk factors and other cautionary statements described in “Part I, Item 1A. Risk Factors” included elsewhere in this Form 10-K.

Overview

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. We have ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, all located in the Western Eagle Ford in South Texas. Our assets include our wholly-owned Western Catarina Midstream gathering system, our wholly-owned Seco Pipeline, and a 50% interest in 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 2018

Some key highlights of our business activities for the year ended December 31, 2018 were:

- In April 2018, we completed the Briggs Divestiture for cash consideration of approximately $4.2 million.
- In May 2018, we completed the Cola Divestiture for cash consideration of approximately $1.0 million.
- In May 2018, we executed a series of agreements with Targa and other parties pursuant to which we formed an expanded 50 / 50 joint venture with Targa in South Texas, the Carnero JV, and received an acreage dedication from Sanchez Energy and its working interest partners of over 315,000 Comanche acres in the Western Eagle Ford pursuant to a new long-term firm gas gathering and processing agreement.
- In October 2018, we completed the Louisiana Divestiture for cash consideration of approximately $1.3 million.

How We Evaluate Our Operations

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

- our throughput volumes on Western Catarina Midstream and the Seco Pipeline;
- our operating expenses; and
- our Adjusted EBITDA, a non-GAAP financial measure (for a definition of Adjusted EBITDA please read “Non-GAAP Financial Measures-Adjusted EBITDA”).

Throughput Volumes

Upon the acquisition of Western Catarina Midstream, our management began to analyze our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within the dedicated areas in order to maintain or increase throughput volumes on Western Catarina Midstream. Our success in connecting additional wells is impacted by successful drilling activity by Sanchez Energy on the acreage

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dedicated to Western Catarina Midstream, our ability to secure volumes from Sanchez Energy from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure. Construction of the Seco Pipeline was completed in August 2017, and throughput volumes are dependent on gas processed at the Raptor Gas Processing Facility and demand for dry gas in markets in South Texas. Natural gas is currently being transported through the Seco Pipeline under the Seco Pipeline Transportation Agreement. Future throughput volumes on the Seco Pipeline are dependent on the continuation of this month-to-month agreement with Sanchez Energy, execution of a new agreement with Sanchez Energy, or execution of an agreement with a third-party.

Operating Expenses

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

We believe that the presentation of Adjusted EBITDA provides useful information to investors in assessing our financial condition and results of operations. The most directly comparable GAAP measure 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 their utility.

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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, 2018	2017
Net income (loss)	$ 15,691	$ (3,040)
Adjusted by:		
Interest expense, net	10,961	8,341
Income tax expense	190	—
Depreciation, depletion and amortization	25,987	34,830
Asset impairments	—	4,688
Accretion expense	497	773
Gain on sale of assets	(3,186)	(4,150)
Unit-based compensation expense	1,938	3,373
Unit-based asset management fees	8,646	8,820
Distributions in excess of equity earnings	9,754	5,792
(Gain) loss on mark-to-market activities	(3,229)	7,558
Commodity derivatives settled early	—	(3,602)
Acquisition and divestiture costs	2,150	1,646
Adjusted EBITDA	$ 69,399	$ 65,029

Significant Operational Factors

· Throughput. During the year ended December 31, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.8 MBbls/d of oil, 157.2 MMcf/d of natural gas and 11.0 MBbls/d of water. During the year ended December 31, 2018, Sanchez Energy transported average daily production through Seco Pipeline of approximately 35.4 MMcf/d of natural gas. During the year ended December 31, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.6 MBbls/d of oil, 163.9 MMcf/d of natural gas and 12.2 MBbls/d of water. During the year ended December 31, 2017, Sanchez Energy transported average daily production through Seco Pipeline of approximately 61.1 MMcf/d of natural gas.
· Production. Our production for the year ended December 31, 2018 was 439 MBoe, or an average of 1,203 Boe/d, compared to approximately 936 MBoe, or an average of 2,565 Boe/d, for the same period in 2017.
· Capital Expenditures. 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. For the year ended December 31, 2017, we spent approximately $32.8 million in capital expenditures, consisting of $2.5 million related to the development of Western Catarina Midstream and $30.3 million related to the development of the Seco Pipeline.
· Hedging Activities. For the year ended December 31, 2018, the non-cash mark-to-market gain for our commodity derivatives was approximately $2.7 million, compared to a loss of $5.2 million for the same period in 2017.

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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, 2018	2017	Variance		
Revenues:					
Gathering and transportation sales	$ 6,651	$ 55,825	$ (49,174)	NM	(a)
Gathering and transportation lease revenues	53,025	—	53,025	NM	(a)
Total gathering and transportation sales	59,676	55,825	3,851	7	%
Operating costs:					
Lease operating expenses	1,145	928	217	23	%
Transportation operating expenses	12,316	11,600	716	6	%
Depreciation and amortization	21,189	25,308	(4,119)	(16)	%
Accretion expense	299	274	25	9	%
Total operating expenses	34,949	38,110	(3,161)	(8)	%
Other income:					
Earnings from equity investments	12,859	7,986	4,873	61	%
Operating income	$ 37,586	$ 25,701	$ 11,885	46	%

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

Gathering and transportation sales. Gathering and transportation sales decreased approximately $49.1 million to approximately $6.7 million for the year ended December 31, 2018, compared to approximately $55.8 million during the same period in 2017. This decrease was attributable to the disaggregation of gathering and transportation sales as we began accounting for revenues from the Seco Pipeline under Topic 606 at the beginning of 2018, while revenues from the Gathering Agreement are accounted for under ASC 840. Total gathering and transportation sales increased approximately $3.9 million, or 7%, to approximately $59.7 million compared to approximately $55.8 million for the same period in 2017. This increase was due to the Seco Pipeline being in service for a full year during the year ended December 31, 2018 compared to a partial year for the year ended December 31, 2017 starting in August 2017 when the Seco Pipeline went into service.

Gathering and transportation lease revenues. Gathering and transportation leave revenues were approximately $53.0 million for the year ended December 31, 2018. Gathering and transportation lease revenues were not reported during the year ended December 31, 2017.

Lease operating expenses. Lease operating expenses, which include ad valorem taxes, increased approximately $0.2 million, or 23%, to $1.1 million for the year ended December 31, 2018, compared to approximately $0.9 million during the same period in 2017. This increase was the result of additional ad valorem taxes incurred on the Seco Pipeline during 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 increased approximately $0.7 million, or 6%, to approximately $12.3 million for the year ended December 31, 2018, compared to approximately $11.6 million during the same period in 2017. The increase was due to the Seco Pipeline being in service for a full year during the year ended December 31, 2018 compared to a partial year for the year ended December 31, 2017.

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Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense decreased approximately $4.1 million, or 16%, to approximately $21.2 million for the year ended December 31, 2018, compared to approximately $25.3 million during the same period in 2017. The decrease was the result of accelerated depreciation recognized at the beginning of 2017 relating to a decrease in estimated useful life on some of our midstream assets.

Earnings from equity investments. Earnings from equity investments increased approximately $4.9 million, or 61%, to approximately $12.9 million for the year ended December 31, 2018, compared to approximately $8.0 million for the same period in 2017. This increase was the result of benefitting from a full year of earnings in the Raptor Gas Processing facility for the year ended December 31, 2018.

Production Operating Results

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

	Years Ended December 31, 2018	2017	Variance		
Revenues:					
Natural gas sales at market price	$ 1,037	$ 6,054	$ (5,017)	(83)	%
Natural gas hedge settlements	(37)	2,730	(2,767)	NM	(a)
Natural gas mark-to-market activities	(47)	(2,067)	2,020	NM	%
Natural gas total	953	6,717	(5,764)	(86)	%
Oil sales	19,872	20,417	(545)	(3)	%
Oil hedge settlements	(1,330)	6,422	(7,752)	NM	(a)
Oil mark-to-market activities	2,730	(3,138)	5,868	NM	(a)
Oil total	21,272	23,701	(2,429)	(10)	%
NGL sales	1,709	1,997	(288)	(14)	%
Miscellaneous expense	—	(91)	91	NM	(a)
Total revenues	23,934	32,324	(8,390)	(26)	%
Operating costs:					
Lease operating expenses	6,719	12,066	(5,347)	(44)	%
Cost of sales	—	77	(77)	(100)	%
Production taxes	1,104	1,476	(372)	(25)	%
Gain on sale of assets	(3,186)	(4,150)	964	23	%
Depreciation, depletion and amortization	4,798	9,522	(4,724)	(50)	%
Asset impairments	—	4,688	(4,688)	(100)	%
Accretion expense	198	499	(301)	(60)	%
Total operating expenses	9,633	24,178	(14,545)	(60)	%
Other income:					
Loss from equity investments	—	(101)	101	NM	(a)
Operating income	$ 14,301	$ 8,045	$ 6,256	78	%

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

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	Years Ended December 31, 2018	2017	Variance		
Net production:					
Natural gas (MMcf)	434	2,521	(2,087)	(83)	%
Oil production (MBbl)	296	414	(118)	(29)	%
NGLs (MBbl)	71	102	(31)	(30)	%
Total production (MBoe)	439	936	(497)	(53)	%
Average daily production (Boe/d)	1,203	2,565	(1,362)	(53)	%
Average sales prices:					
Natural gas price per Mcf with hedge settlements	$ 2.30	$ 3.48	$ (1.18)	(34)	%
Natural gas price per Mcf without hedge settlements	$ 2.39	$ 2.40	$ (0.01)	(0)	%
Oil price per Bbl with hedge settlements	$ 62.64	$ 64.83	$ (2.19)	(3)	%
Oil price per Bbl without hedge settlements	$ 67.14	$ 49.32	$ 17.82	36	%
NGL price per Bbl without hedge settlements	$ 24.07	$ 19.58	$ 4.49	23	%
Total price per Boe with hedge settlements	$ 48.41	$ 40.19	$ 8.22	20	%
Total price per Boe without hedge settlements	$ 51.52	$ 30.41	$ 21.11	69	%
Average unit costs per Boe:					
Field operating expenses (a)	$ 17.82	$ 14.47	$ 3.35	23	%
Lease operating expenses	$ 15.31	$ 12.89	$ 2.42	19	%
Production taxes	$ 2.51	$ 1.58	$ 0.93	59	%
Depreciation, depletion and amortization	$ 10.93	$ 10.17	$ 0.76	7	%

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

Production: For the year ended December 31, 2018, 67% of our production was oil, 16% was NGLs and 17% was natural gas compared to the year ended December 31, 2017, where 44% of our production was oil, 11% was NGLs and 45% 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 and 2017 that were rich in natural gas. Combined production has decreased by 497 MBoe for the year ended December 31, 2018, primarily due to the closing of the Briggs Divestiture, Oklahoma Production Divestiture and the Texas Production Divestiture.

Sales of natural gas, NGLs and oil. Unhedged oil sales decreased approximately $0.5 million, or 3%, to approximately $19.9 million for the year ended December 31, 2018, compared to approximately $20.4 million for the same period in 2017. Sales of NGLs decreased approximately $0.3 million, or 14%, to approximately $1.7 million for the year ended December 31, 2018, compared to approximately $2.0 million for the same period in 2017. Unhedged natural gas sales decreased approximately $5.0 million, or 83%, to approximately $1.0 million for the year ended December 31, 2018, compared to approximately $6.0 million for the same period in 2017. The total decrease in sales of natural gas, NGLs and oil for the year ended December 31, 2018 was primarily the result of decreased production in connection with the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture, which was partially offset by increased realized oil prices.

Including hedges and mark-to-market activities, our total production-related revenue decreased approximately $8.4 million for the year ended December 31, 2018, compared to the same period in 2017. This decrease was primarily the result of approximately $10.5 million of additional losses on hedge settlements and a decrease in sales of approximately $5.9 million, partially offset by an approximately $7.9 million gain on mark-to-market activities.

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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, 2018 compared to the year ended December 31, 2017 (in thousands, except average sales prices and volumes):

	2018 Average Sales Price	2017 Average Sales Price	Average Sales Price Difference	2018 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (MMcf)	$ 2.39	$ 2.40	$ (0.01)	434	$ (4)
Oil (MBbl)	$ 67.14	$ 49.32	$ 17.82	296	$ 5,275
NGLs (MBbl)	$ 24.07	$ 19.58	$ 4.49	71	$ 319
Total oil equivalent (MBoe)	$ 51.52	$ 30.41	$ 21.11	439	$ 5,590

	2018 Production Volume	2017 Production Volume	Production Volume Difference	2017 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	434	2,521	(2,087)	$ 2.40	$ (5,009)
Oil (MBbl)	296	414	(118)	$ 49.32	$ (5,820)
NGLs (MBbl)	71	102	(31)	$ 19.58	$ (607)
Total oil equivalent (MBoe)	439	936	(497)	$ 30.41	$ (11,436)

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, 2018 by $2.3 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, 2018, the non-cash mark-to-market gains were approximately $2.7 million, compared to a loss of approximately $5.2 million for the same period in 2017. The 2018 non-cash gain resulted from lower future expected oil prices on these derivative transactions. Cash payments made for our commodity derivatives were approximately $1.4 million for the year ended December 31, 2018, compared to settlements received of approximately $9.1 million for the year ended December 31, 2017.

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

Lease operating expenses. Lease operating expenses decreased approximately $5.4 million, or 44%, to approximately $6.7 million for the year ended December 31, 2018, compared to $12.1 million for the same period in 2017. This decreased in operating expenses was primarily due to the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture.

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

Our depreciation, depletion and amortization expense for the year ended December 31, 2018 was approximately $4.8 million, compared to approximately $9.5 million for the same period in 2017. The decrease is primarily the result of the Briggs Divestiture, Oklahoma Production Divestiture and Texas Production Divestiture. Our non-oil and natural gas properties are depreciated using the straight-line basis.

Impairment expense. For the year ended December 31, 2018, we did not record impairment on our oil and natural gas properties. During the same period in 2017, our non-cash impairment charges were approximately $4.7 million, to impair certain of our oil and natural gas properties in Texas. The impairment expense recorded during the year ended

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December 31, 2017 resulted from decreases in expectations for oil and natural gas prices in the future as well as changes to our expected future production estimates in certain areas.

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, 2018	2017	Variance		
Reconciliation of segment operating income to net income (loss)					
Total production operating income	$ 14,301	$ 8,045	$ 6,256	78	%
Total midstream operating income	37,586	25,701	11,885	46	%
Total segment operating income	51,887	33,746	18,141	54	%
General and administrative expense	(23,653)	(22,655)	(998)	4	%
Unit-based compensation expense	(1,938)	(3,373)	1,435	(43)	%
Interest expense, net	(10,961)	(8,341)	(2,620)	31	%
Other income (expense)	546	(2,417)	2,963	NM	(a)
Income tax expense	(190)	—	(190)	NM	(a)
Net income (loss)	$ 15,691	$ (3,040)	$ 18,731	NM	(a)

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

General and administrative expense. General and administrative expenses include the costs of employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, remained flat for the years ended December 31, 2018 and 2017.

Unit-based compensation expense. Unit-based compensation expense decreased approximately $1.4 million, or 43%, to approximately $1.9 million for the year ended December 31, 2018, compared to approximately $3.3 million for the same period in 2017. This decrease was the result of a substantial decline in the price of our common units on the NYSE American during the latter half of the year ended December 31, 2018.

Interest expense, net. Interest expense increased approximately $2.6 million, or 31%, to approximately $10.9 million for the year ended December 31, 2018, compared to approximately $8.3 million for the same period in 2017. This increase was the result of an overall increase in interest rates, as well as borrowings under our Credit Agreement which primarily occurred in the second half of 2017 to fund development of the Seco Pipeline and capital projects in our joint ventures with Targa

Other income (expense). Other income (expense) was approximately $0.5 million for the year ended December 31, 2018, compared to approximately $2.4 million for the same period in 2017, 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 year ended December 31, 2018, compared to no expense recorded for the same period in 2017. The increase resulted from income taxes on gross margin within the state of Texas, which was primarily driven by a decrease in total operating expenses over the comparable periods and the removal of the valuation allowance.

Liquidity and Capital Resources

As of December 31, 2018, we had approximately $2.9 million in cash and cash equivalents and approximately $30.0 million available for borrowing under the Credit Agreement in effect on such date, as discussed below. During the years ended December 31, 2018 and 2017, we paid approximately $9.8 million and $7.5 million, respectively, in cash for interest

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on borrowings under our Credit Agreement, of which approximately $0.1 million was related to the commitment fee on undrawn commitments.

Our capital expenditures during the year ended December 31, 2018 were funded with cash on hand. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional 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 expected quarterly cash distributions.

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

Credit Agreement

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

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our oil and natural gas properties and our midstream assets. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of $15.0 million which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was $200.0 million. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports 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 and the amount of distributions received from Carnero JV multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders. As of December 31, 2018, the borrowing base under the Credit Agreement was $310.0 million, with an elected commitment amount of $210.0 million. On January 4, 2019, we received a notification that, pursuant to the terms of the Credit Agreement, our lenders had undertaken a borrowing base review, which resulted in a borrowing base redetermination of $303.1 million. The elected commitment amount remained unchanged at $210.0 million.

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

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

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

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

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

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

At December 31, 2018, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Sources of Debt and Equity Financing

As of December 31, 2018, the borrowing base under our Credit Agreement was set at $310.0 million, with an elected commitment amount of $210.0 million and we had $180.0 million of debt outstanding under the facility, leaving us with $30.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement at December 31, 2018. Our Credit Agreement matures on March 31, 2020.

In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately $1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015 as updated by that certain prospectus supplement filed with the SEC on April 6, 2017 (the “Shelf Registration Statement”). The Shelf Registration Statement allows us to sell up to $50.0 million of common units by any method deemed an “at the market offering” (as such term is defined in Rule 415 of the Securities Act). Also in April 2017, we entered into an At Market Issuance Sales Agreement with FBR Capital Markets & Co. (“FBR”) pursuant to which we may issue and sell through FBR, acting as sales agent, common units. Proceeds from such sales are expected to be used for general limited partnership purposes.

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Commitments and Contractual Obligations

As of December 31, 2018, our contractual obligations included our long-term debt, in the form of a Credit Agreement, asset retirement obligations ("ARO"), earnout derivative and compressor commitments. The following table summarizes our contractual obligations as of December 31, 2018 (in thousands):

	Less than 1 Year	1-3 Years	3-5 Years	More than 5 years	Total
Long-Term Debt	$ —	$ 180,000	$ —	$ —	$ 180,000
ARO(a)	—	—	—	6,200	6,200
Earnout derivative(b)	125	1,223	2,358	2,150	5,856
Compressors	535,300	—	—	—	535,300
Total	$ 535,425	$ 181,223	$ 2,358	$ 8,350	$ 727,356

(a) Amounts represent the present value of our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 10 "Asset Retirement Obligations."

(b) Amounts represent the present value of our estimate of future earnout obligations. These costs are contingent and subject to various factors, which are discussed in Note 5 "Fair Value Measurements."

Open Commodity Hedge Positions

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

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

The following tables as of December 31, 2018, summarize our hedges currently in place. 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
2019	119,832	$ 2.85	115,784	$ 2.85	112,032	$ 2.85	108,552	$ 2.85	456,200	$ 2.85
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85
									858,648	

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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
2019	62,528	$ 60.41	59,552	$ 60.44	57,024	$ 60.48	54,824	$ 60.52	233,928	$ 60.46
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50
									434,512	

Operating Cash Flows

Our net operating cash flows provided by operating activities for the year ended December 31, 2018, were approximately $66.9 million, compared to net cash flow provided by operating activities of approximately $52.1 million for the same period in 2017. This increase was primarily related to the impact of higher average commodity prices between the periods resulting in an increase of approximately $5.6 million, as well as return from equity investment greater than equity earnings for the period of approximately $11.3 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

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 Processing and Carnero Gathering 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.

Our net cash flows used in investing activities for the year ended December 31, 2017 were approximately $32.7 million, consisting of approximately $31.7 million related to midstream activities, including pipeline construction, and contributions to Carnero Processing and Carnero Gathering totaling approximately $13.7 million. These outflows were offset by approximately $11.7 million related to proceeds from sales of oil and natural gas properties

Financing Activities

Our cash flows used in financing activities were approximately $66.6 million for the year ended December 31, 2018, compared to approximately $20.1 million used by financing activities for the same period in 2017. 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 approximately $11.0 million of borrowings under the Credit Agreement.

Our cash flows used in financing activities were approximately $20.1 million for the year ended December 31, 2017. During the year ended December 31, 2017, we had borrowings under our Credit Agreement of approximately $48.0 million and proceeds from issuance of common units of approximately $1.3 million. During the year ended December 31, 2017 we distributed approximately $31.5 million to Stonepeak Catarina, as the holder of all of our outstanding Class B Preferred Units and approximately $25.2 million to our common unitholders. Additionally, we paid approximately $0.6 million in offering costs and repaid approximately $12.0 million of borrowings.

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Off-Balance Sheet Arrangements

As of December 31, 2018, we had no off-balance sheet arrangements with third parties, and we maintain no debt obligations that contain 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. 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 71% of total revenue for the year ended December 31, 2018. Any development that materially and adversely affects Sanchez Energy's operations or financial condition could have a material adverse impact on us. Additional information on the risks associated with our business dealings with Sanchez Energy, please read "Part I, Item 1A. Risk Factors." As of December 31, 2018, we had no past due receivables from Sanchez Energy, and through December 31, 2018, we have not suffered any significant losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Derivative Counterparties

As of December 31, 2018, 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, 2018, each of these financial institutions had an investment grade credit rating.

Credit Agreement

As of December 31, 2018, the banks and their percentage commitments in our Credit Agreement were: Royal Bank of Canada (13%), Compass Bank (12%), SunTrust Bank (12%), Capital One, N.A. (12%), Comerica Bank (12%), CIT Bank, N.A. (8.5%), Citibank, N.A. (8.5%), Credit Suisse AG, Cayman Islands (8.5%), ING Capital LLC (8.5%), and Macquarie Investments US Inc (5%). As of December 31, 2018, 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 these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions. The results of these estimates and assumptions form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements.

As of December 31, 2018, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017, which was filed with the SEC on March 12, 2018. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read 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.

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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, and up to 36 years for gathering facilities.

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. Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. 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. 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 2018 and 2017 were prepared using Ryder Scott’s estimates of our proved reserves.

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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.

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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, 2018 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2018, 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, 2018.

KPMG LLP, an independent registered public accounting firm, has issued its report on the effectiveness of our internal control over financial reporting at December 31, 2018. The report from KPMG, LLP is included in this Item 8 under the heading “Report of Independent Registered Public Accounting Firm.”

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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.

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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 7, 2019. 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, resignation, removal or disqualification. 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	51	Independent Director
Kirsten A. Hink	52	Chief Accounting Officer
Jack Howell	32	Director
Richard S. Langdon	68	Independent Director
G.M. Byrd Larberg	66	Independent Director
Antonio R. Sanchez, III	45	Director; Chairman of the Board
Eduardo A. Sanchez	39	Director
Patricio D. Sanchez	38	Director; President & Chief Operating Officer
Luke R. Taylor	41	Director
Charles C. Ward	58	Chief Financial Officer and Secretary
Gerald F. Willinger	51	Director; Chief Executive Officer

Alan S. Bigman was elected as a director of our general partner 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 and is the Chair of the Audit Committee. 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. Mrs. Hink has served as Senior Vice President – Chief Accounting Officer of Sanchez Oil & Gas Corporation since March 2016. Prior to joining Sanchez Energy,

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Mrs. Hink served as the 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 Chapter 11 bankruptcy protection in October 2009. Mrs. Hink is a Certified Public Accountant in the State of Texas.

Jack Howell was elected as a director of our general partner in October 2015. Mr. Howell has been with Stonepeak since 2015. Mr. Howell currently serves as a Senior Managing Director at the firm. Prior to joining Stonepeak, he 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 from 2009 to 2011.

Richard S. Langdon was elected as a director of our general partner 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 Chapter 11 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 director of our general partner 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 also serves as a member of the board of directors of Horizon Energy, a private Exploration Company with both Domestic and International focus, which position he has held since late 2016. 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 the Houston Metropolitan YMCA, as past chairman of the board. He was a board member 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 twenty-one years, he held various leadership positions within Shell, 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 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. Clients have included Pemex, Maersk, ONGC, Ecopetrol, Repsol, HOCOL and the Kuwait National Petroleum Company.

Antonio R. Sanchez, III was elected as a director of our general partner 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 has served 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. 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 director of our general partner 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. 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 a director 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 Executive Vice President. Mr. Sanchez has served as an Executive Vice President of Sanchez Energy since November 2016. 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 director of our general partner in October 2015. Mr. Taylor has served as a Senior Managing Director with Stonepeak since August 2011 and has served as a member of Stonepeak's investment committee since 2015. In addition to serving a director of our general partner, Mr. Taylor currently sits on the boards of the following private companies: Golar Power, which develops, owns and operates integrated LNG-based transportation and downstream solutions, Ironclad Energy Partners, which develops, owns and operates energy generation and utility infrastructure assets, and Lineage Logistics, a warehousing and cold storage logistics company. Mr. Taylor is a former director of the following private companies: Paradigm Energy Partners, Orion Holdings, Tidewater Holdings, Casper Crude Rail Holdings and Northstar Renewable Power. Prior to joining Stonepeak, Mr. Taylor was a Senior Vice President with Macquarie Capital based in New York from August 2005 to May 2011.

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 director of our general partner 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.

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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 to the Board in October 2015 pursuant the Representation and Standstill Agreement. Pursuant to the Representation and Standstill Agreement, we and our general partner agreed to permit Stonepeak to designate two persons to serve on the Board. The right to designate one Board member will immediately terminate on such date as Stonepeak no longer owns at least 25% of the outstanding Class B Preferred Units issued to it; and the right to designate the second Board member will immediately terminate on such date as no Class B Preferred Units are outstanding. Stonepeak also has the right to appoint the three independent members to the Board if all of the Class B Preferred Units have not been redeemed by December 31, 2021, with such right continuing until all Class B 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 persons to the Board, except for two persons who are appointed 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 as we look to grow the

Partnership.

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, 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.

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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 B Preferred Units to conclude that the persons appointed by them should serve as directors:

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

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

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 equity grants to directors, 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.

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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 charters of the Audit Committee 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 upon request of the Corporate Secretary of our general partner. 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the directors and executive officers of our general partner, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership of our equity securities and reports of changes in ownership of our equity securities with the SEC. Such persons are also required by SEC regulation to furnish us with copies of all Section 16(a) forms that they file.

Based solely on our review of the copies of such forms furnished to us and written representations from the directors and executive officer of our general partner, for the year ended December 31, 2018, one late filing was made by Stonepeak Catarina Holdings, LLC. All other Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner. In connection with the distribution on the Class B Preferred Units for the quarter ended June 30, 2018, the Board elected to pay a portion of the distribution in the form of 310,009 Class B Preferred PIK Units. Such distribution was paid on August 31, 2018. The corresponding Form 4 was filed on February 4, 2019. We are not aware of any other late filings by Section 16(a) reporting persons.

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 19, 2018. 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.

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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 2018 and 2017:

Name and Principal Position	Year	Salary	Cash Bonus (a)	Unit Awards (b)	All Other Compensation (c)	Total
Gerald F. Willinger	2018	$ 600,000	$ 750,000	$ 1,799,980	$ 128,994	$ 3,278,974
Chief Executive Officer (d)	2017	$ 600,000	$ —	$ 1,299,982	$ 192,756	$ 2,092,738
Patricio D. Sanchez	2018	$ 400,000	$ —	$ 1,299,989	$ 52,043	$ 1,752,032
President & Chief Operating Officer (d)(e)	2017	$ 400,000	$ —	$ 899,985	$ 68,152	$ 1,368,137
Charles C. Ward	2018	$ 275,000	$ 350,000	$ 849,995	$ 40,476	$ 1,515,471
Chief Financial Officer and Secretary (d)	2017	$ 275,000	$ —	$ 499,992	$ 17,134	$ 792,126

(a) On January 30, 2019, the Board awarded Messrs. Willinger and Ward cash bonuses of $750,000 and $350,000, respectively, for their work and efforts during 2018.

(b) The amounts reported in this column reflect the aggregate grant date fair value of awards granted, if any, under our Plan for fiscal years 2018 and 2017, 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. For 2017, Messrs. Willinger and Sanchez were each issued 9,090 units under the Plan for director compensation with a grant date fair value of $99,993, based on the $15.70 price per common unit on March 31, 2017, which was the closing price as reported on the NYSE American on the day before the date of grant. On March 21, 2017, the Board awarded executive bonuses for services rendered in 2016, which were paid in the form of restricted units under the Plan to vest one year after the date of grant. Messrs. Willinger, Sanchez and Ward received 82,191, 54,794 and 34,246 restricted units, respectively, with a grant date fair value per common unit of $1,199,989, $799,992, and $499,992, respectively, based on a price per common unit of $14.60, which was the closing price on the date of grant as reported on the NYSE American. For 2018, Messrs. Willinger and Sanchez where each issued 9,090 units under the Plan for director compensation with a grant date fair value of $99,990, based on the $11.00 price per common unit on April 2, 2018. On April 6, 2018, the Board awarded executive bonuses for services rendered in 2017, which were paid in the form of restricted units under the Plan to vest one year after the date of grant. Messrs. Willinger, Sanchez and Ward received 99,585, 99,585 and 45,643 restricted units, respectively, with a grant date fair value per common unit of $1,199,999, $1,199,999, and $549,998, respectively, based on a price per common unit of $12.05, which was the closing price on the date of grant as reported on the NYSE American. In addition, on April 6, 2018, the Board also awarded Messrs. Willinger and Ward long-term incentive awards, which were paid in the form of restricted units under the Plan which vest in equal installments over three years. Messrs. Willinger and Ward received 41,493 and 24,896 restricted units, respectively, with a grant date fair value per common unit of $499,991 and $299,997, respectively, based on a price per common unit of $12.05, which was the closing price on the date of grant as reported on the NYSE American.

(c) The amount in this column reflects the amount of matching contributions made under our 401k plan; parking cost paid for our executive officers; the aggregate incremental cost of the personal use of aircraft made available by SOG and allocated to the Partnership; 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. For Mr. Willinger, the amounts for 2018 and 2017 include $46,000 and $44,500, respectively, in director compensation paid in cash. For Mr. Sanchez, the amounts for 2018 and 2017 include $44,500 and $50,500, respectively, in director compensation paid in cash. For Mr. Willinger, the amounts for 2018 and 2017 include the aggregate incremental cost of the personal use of aircraft made available by SOG, of which $41,168 and $129,866, respectively, were allocated to the Partnership. For Mr. Sanchez, the amount for 2017 includes the aggregate incremental cost of the personal use of aircraft made available by SOG, of which $22,404 was allocated to the Partnership.

(d) Our named executive officers are eligible to participate in benefit plans such as medical, dental, life, and disability insurance, 401k and flexible spending accounts on the same terms as all employees or service providers.

(e) Mr. Sanchez was elected Chief Operating Officer in May 2015 and President & Chief Operating Officer in March 2017.

None of the executive officers of our general partner have employment agreements.

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Outstanding Equity Awards at Fiscal Year-End 2018

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, 2018 for the named executive officers:

Name	Number of Units Not Vested		Fair Market Value of Units Not Vested
Gerald F. Willinger	141,078	(b)	$ 242,654
Patricio D. Sanchez	99,585	(b)	$ 171,286
Charles C. Ward	70,539	(b)	$ 121,327

(a) Amounts are based on the closing price of our common units of $1.72 as reported on the NYSE American on December 31, 2018.
(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. See footnote (a) 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

The Board has approved the following compensation program for its directors for the year ended December 31, 2018:

- 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.

The following table sets forth a summary of the 2018 compensation for the directors the Board except for Messrs. Willinger and Patricio 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	$ 71,000	$ 99,990	$ 21,908	$ 192,898
Jack Howell (c)	$ —	$ —	$ —	$ —
Richard S. Langdon	$ 57,000	$ 99,990	$ 16,004	$ 172,994
G. M. Byrd Larberg	$ 61,000	$ 99,990	$ —	$ 160,990
Antonio R. Sanchez, III	$ 46,000	$ 99,990	$ —	$ 145,990
Eduardo A. Sanchez	$ 43,000	$ 99,990	$ —	$ 142,990
Luke R. Taylor (c)	$ —	$ —	$ —	$ —

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(a) The amounts shown in this column represent the aggregate grant date fair value of the units granted under the Plan, computed in accordance with FASB ASC Topic 718, based on the $11.00 closing price per common unit on April 2, 2018.
(b) All other compensation includes amounts for health insurance premium fees paid by us for the director.
(c) As the designated directors appointed by Stonepeak, Messrs. Howell and Taylor waived any director fees to which they were otherwise entitled.

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 7, 2019, 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 7, 2019. The amounts and percentage of common units and Class B 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 17,464,315 common units and 31,310,896 Class B Preferred Units outstanding as of March 7, 2019, the number of common units beneficially owned and the number of Class B Preferred Units beneficially owned is based upon ownership as of March 7, 2019, unless otherwise specified therein. 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 B Preferred Units Beneficially Owned(1)		Percentage of Total Units Beneficially Owned(1)
Name and address of Beneficial Owner(2)	Number	Percentage	Number	Percentage	
Stonepeak Catarina Holdings, LLC(3)	393,291	2.3 %	31,310,896	100 %	65.0 %
Goldman Sachs Asset Management, L.P.(4)	1,210,600	6.9 %	—	—	2.5 %
SN UR Holdings, LLC(5)	2,272,727	13.0 %	—	—	4.7 %

Alan S. Bigman(6)	31,383	*		—	—	*	
Kirsten A. Hink	23,933	*		—	—	*	
Jack Howell	—	—		—	—	—	
Richard S. Langdon	35,956	*		—	—	*	
G. M. Byrd Larberg	30,225	*		—	—	*	
Antonio R. Sanchez, III(7)	742,089	4.2	%	—	—	1.5	%
Eduardo A. Sanchez	494,329	2.8	%	—	—	1.0	%
Patricio D. Sanchez	683,244	3.9	%	—	—	1.4	%
Luke R. Taylor	—	—		—	—	—	
Charles C. Ward	403,984	2.3	%	—	—	*	
Gerald F. Willinger	983,409	5.6	%	—	—	2.0	%
All directors and executive officers as a group (11 persons)	3,428,552	19.6	%	—	—	7.0	%

*Less than 1%

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(1) The holder of Class B Preferred Units has the right to convert such units into our common units at any time.
(2) Unless otherwise set forth below, the address of all of all beneficial owners is c/o Sanchez Midstream Partners LP, 1000 Main Street, Suite 3000, Houston, Texas 77002.
(3) Ownership data as reported on Schedule 13D/A filed on February 4, 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 principal business address of each reporting person is 717 Fifth Avenue, 25th Floor, New York, New York 10022.The filing lists each filing person as having shared voting and dispositive power over the common units and the Class B Preferred Units.
(4) Ownership data as reported on Schedule 13G/A filed on February 6, 2019 by Goldman Sachs Asset Management, L.P. and GS Investment Strategies, LLC. The principal business address of the reporting person is Goldman Sachs Asset Management, 200 West Street, New York, NY 10282. The filing lists each filing person as having shared voting and dispositive power over the common units.
(5) Ownership data as reported on Schedule 13G 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.
(6) Of these common units, 1,000 are held by Mr. Bigman's minor children.
(7) 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, 2018:

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	—	$ —	1,309,385
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	1,309,385

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. Each of these fees, not including the reimbursement of costs, will be paid in cash unless Manager elects for such fee to be paid in our equity. 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 year ended December 31, 2018, Manager elected to receive 1,566,316 common units equal to approximately $8.6 million, in lieu of cash. During the years ended December 31, 2018 and 2017, we incurred costs of approximately $8.6 million and $8.8 million, respectively, to Manager under the Services Agreement.

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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, 2018 and 2017, SOG received $0.3 million and $0.4 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 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 February 26, 2019 by Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez was 6.5%, 3.2%, 1.2% and 1.3%, respectively.

We entered into the Gathering Agreement with Sanchez Energy in October 2015. For the years ended December 31, 2018 and 2017, Sanchez Energy paid us approximately $57.9 million and $52.8 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. Following March 31, 2018, we have agreed with Sanchez Energy to continue the incremental infrastructure fee on a month-to-month basis.

In September 2017, we entered into the Seco Pipeline Transportation Agreement. For the years ended December 31, 2018 and 2017, Sanchez Energy paid us approximately $7.2 million and $0.9 million, respectively, pursuant to the terms of such agreement.

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, 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 holders of record on August 21, 2018.

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, 2018 and 2017.

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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, 2018 and 2017 were $1,192,912 and $816,000, respectively.

Audit-Related Fees. There were no audit-related fees billed by KPMG for the year ended December 31, 2018. The aggregate fees billed for audit-related fees for the year ended December 31, 2017 was $215,000.

Tax Fees. There were no tax fees billed by KPMG for the years ended December 31, 2018 and 2017.

All Other Fees. There were no other fees billed by KPMG for the year ended December 31, 2018. The aggregate fees billed for other fees for the year ended December 31, 2017 was $36,000.

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.

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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.

HIDDEN_ROW 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).

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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	Second 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 Production Partners LP on October 14, 2015, File No. 001-33147).
3.5	

	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Sanchez Production Partners LP, effective as of January 25, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on January 27, 2017, File No. 001-33147).
3.6	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Sanchez Midstream Partners LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 15, 2017, File No. 001-33147).

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3.7	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).
3.8	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).

3.9	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).
3.10	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).
4.1	Registration Rights

	Agreement, dated as of October 14, 2015, between Sanchez Production Partners LP and the purchaser named therein (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
4.2	Amendment No. 1 to Registration Rights Agreement, effective January 25, 2017, by and between Stonepeak Catarina Holdings LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on January 27, 2017, File No. 001-33147).

4.3	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).
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).

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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*	Summary Compensation of Executive Officers of Sanchez Midstream Partners GP LLC.
10.12*	Summary Compensation of Directors of Sanchez Midstream Partners GP LLC.
10.13	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).
10.14	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).
10.15	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).

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10.16	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).
10.17	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).
10.18	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).
10.19+	Board Representation and Standstill Agreement, dated as of October 14, 2015, between Sanchez Production Partners LP and the purchaser named therein (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on

	October 14, 2015, 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.
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.

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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.

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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 7, 2019	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 7, 2019
/s/ Gerald F. Willinger	Director; Chief Executive Officer	March 7, 2019

Gerald F. Willinger	(Principal Executive Officer)	
/S/ Charles C. Ward Charles C. Ward	Chief Financial Officer & Secretary (Principal Financial Officer)	March 7, 2019
/S/ Patricio D. Sanchez Patricio D. Sanchez	Director; President & Chief Operating Officer (Principal Operating Officer)	March 7, 2019
/S/ Kirsten A. Hink Kirsten A. Hink	Chief Accounting Officer (Principal Accounting Officer)	March 7, 2019
/S/ Alan S. Bigman Alan S. Bigman	Director	March 7, 2019
/S/ Jack Howell Jack Howell	Director	March 7, 2019
/S/ Richard S. Langdon Richard S. Langdon	Director	March 7, 2019
/S/ G. M. Byrd Larberg G. M. Byrd Larberg	Director	March 7, 2019
/S/ Eduardo A. Sanchez Eduardo A Sanchez	Director	March 7, 2019
/S/ Luke R Tayler Luke R. Taylor	Director	March 7, 2019

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Sanchez Midstream Partners LP and the Board of Directors of

Sanchez Midstream Partners GP LLC:

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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 7, 2019 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 3 to the consolidated financial statements, the Partnership has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification Topic 606 Revenue from Contracts with Customers.

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 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. 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 7, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Sanchez Midstream Partners LP and the Board of Directors of

Sanchez Midstream Partners GP LLC:

Opinion on Internal Control Over Financial Reporting

We have audited Sanchez Midstream Partners LP and subsidiaries' (the Partnership) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2018 and 2017, the related consolidated statements of operations, change in partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated March 7, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/KPMG LLP

Houston, Texas
March 7, 2019

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Consolidated Statements of Operations

(In thousands, except unit data)

	Years Ended December 31, 2018	2017
Revenues		
Natural gas sales	$ 953	$ 6,626
Oil sales	21,272	23,701
Natural gas liquid sales	1,709	1,997
Gathering and transportation sales	6,651	55,825
Gathering and transportation lease revenues	53,025	—
Total revenues	83,610	88,149
Expenses		
Operating expenses		
Lease operating expenses	7,864	12,994
Transportation operating expenses	12,316	11,600
Cost of sales	—	77
Production taxes	1,104	1,476
General and administrative expenses	23,653	22,655
Unit-based compensation expense	1,938	3,373
Gain on sale of assets	(3,186)	(4,150)
Depreciation, depletion and amortization	25,987	34,830
Asset impairments	—	4,688
Accretion expense	497	773
Total operating expenses	70,173	88,316
Other (income) expense		
Interest expense, net	10,961	8,341
Earnings from equity investments	(12,859)	(7,885)
Other (income) expense	(546)	2,417
Total other (income) expenses	(2,444)	2,873
Total expenses	67,729	91,189
Income (loss) before income taxes	15,881	(3,040)
Income tax expense	190	—
Net income (loss)	15,691	(3,040)
Less		
Preferred unit paid-in-kind distributions	(3,500)	(2,625)
Preferred unit distributions	(33,425)	(33,250)
Preferred unit amortization	(2,358)	(1,796)
Net loss attributable to common unitholders	$ (23,592)	$ (40,711)
Net loss per unit		
Common units - Basic and Diluted	$ (1.55)	$ (2.90)
Weighted Average Units Outstanding		

Common units - Basic and Diluted	15,264,284	14,039,726

See accompanying notes to consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Consolidated Balance Sheets

(In thousands, except unit data)

	December 31, 2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,934	$ 321
Accounts receivable	277	495
Accounts receivable - related entities	6,700	13,099
Prepaid expenses	931	2,670
Fair value of commodity derivative instruments	3,044	942
Total current assets	13,886	17,527
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	112,173	170,750
Gathering and transportation assets	186,406	184,969
Less: accumulated depreciation, depletion, amortization and impairment	(100,245)	(142,574)
Oil and natural gas properties and equipment, net	198,334	213,145
Other assets		
Intangible assets, net	158,706	172,166
Fair value of commodity derivative instruments	876	1,318
Equity investments	114,465	123,715
Other non-current assets	418	552
Total assets	$ 486,685	$ 528,423
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 4,678	$ 1,782
Accounts payable and accrued liabilities - related entities	5,641	10,353
Royalties payable	359	371
Fair value of commodity derivative instruments	6	756
Other liabilities	125	151
Total current liabilities	10,809	13,413
Other liabilities		
Asset retirement obligation	6,200	6,074
Long-term debt, net of debt issuance costs	178,582	187,808
Fair value of commodity derivative instruments	—	273
Other liabilities	5,857	6,251
Total other liabilities	190,639	200,406
Total liabilities	201,448	213,819
Commitments and contingencies (See Note 13)		

Mezzanine equity		
Class B preferred units, 31,310,896 and 31,000,887 units issued and outstanding as of December 31, 2018 and 2017, respectively	349,857	343,912
Partners' deficit		
Common units, 16,486,239 and 14,965,134 units issued and outstanding as of December 31, 2018 and 2017, respectively	(64,620)	(29,308)
Total partners' deficit	(64,620)	(29,308)
Total liabilities and partners' capital	$ 486,685	$ 528,423

See accompanying notes to consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Consolidated Statements of Cash Flows

(In thousands)

	Years Ended December 31, 2018	2017
Cash flows from operating activities:		
Net income (loss)	$ 15,691	$ (3,040)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	12,527	21,262
Amortization of debt issuance costs	783	524
Asset impairments	—	4,688
Accretion expense	497	773
Distributions from equity investments	24,946	8,720
Equity earnings in affiliate	(12,859)	(7,885)
Gain on sale of assets	(3,186)	(4,150)
Net gains on commodity derivative contracts	(1,316)	(3,947)
Net cash settlements received (paid) on commodity derivative contracts	(1,326)	5,487
Cash settlements on terminated commodity derivative contracts	—	3,602
Unit-based compensation	1,938	3,373
(Gain) loss on earnout derivative	(546)	2,353
Amortization of intangible assets	13,460	13,568
Costs for plug and abandon activities	—	(60)
Changes in Operating Assets and Liabilities:		
Accounts receivable	(377)	644
Accounts receivable - related entities	6,389	(6,590)
Prepaid expenses	1,739	(629)
Other assets	82	144
Accounts payable and accrued liabilities	13,719	9,997
Accounts payable and accrued liabilities- related entities	(5,333)	3,566
Royalties payable	(12)	(300)
Other long-term liabilities	126	—
Net cash provided by operating activities	66,942	52,100
Cash flows from investing activities:		
Final settlement of oil and natural gas properties acquisition	—	1,468
Development of oil and natural gas properties	(11)	(441)
Proceeds from sale of assets	7,692	11,665
Construction of gathering and transportation assets	(2,533)	(31,693)
Purchases of and contributions to equity affiliates	(2,838)	(13,684)
Net cash provided by (used in) investing activities	2,310	(32,685)
Cash flows from financing activities:		
Payments for offering costs	(50)	(611)
Proceeds from issuance of debt	2,000	48,000

Repayment of debt	(11,000)	(12,000)
Issuance of common units	—	1,290
Distributions to common unitholders	(23,243)	(25,192)
Class B preferred unit cash distributions	(33,338)	(31,500)
Debt issuance costs	(1,008)	(38)
Net cash used in financing activities	(66,639)	(20,051)
Net increase (decrease) in cash and cash equivalents	2,613	(636)
Cash and cash equivalents, beginning of period	321	957
Cash and cash equivalents, end of period	$ 2,934	$ 321
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 525	$ 1,064
Cash paid during the period for interest	$ 9,763	$ 7,643

See accompanying notes to consolidated financial statements.

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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' Capital, December 31, 2016	13,447,749	$ 16,744	$ 16,744
Unit-based compensation programs	217,481	3,373	3,373
Issuance of common units, net of offering costs of $0.6 million	906,613	11,228	11,228
Cash distributions to common unit holders	—	(25,192)	(25,192)
Common units issued as Class B Preferred distributions	393,291	5,250	5,250
Distributions - Class B preferred units	—	(37,671)	(37,671)
Net loss	—	(3,040)	(3,040)
Partners' Deficit, December 31, 2017	14,965,134	$ (29,308)	$ (29,308)
Unit-based compensation programs	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)

See accompanying notes to consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2018 and 2017

1. ORGANIZATION AND BUSINESS

Organization

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. We have ownership stakes in oil and natural gas gathering systems, natural gas pipelines, and a natural gas processing facility, all located in the Western Eagle Ford in South Texas. We also own production assets in Texas and Louisiana. We have entered into the Services Agreement with Manager, the sole member of our general partner, pursuant to which Manager provides services we require to operate 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 also 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. 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 are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In June 2018, the FASB issued ASU 2018-07 “Compensation - Stock Compensation (Topic 718) - Improvements to Nonemployee Share-Based Payment Accounting,” which expands the scope of Topic 718, Compensation – Stock

Compensation, to include share-based payment transactions for acquiring goods and services from nonemployees. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2018. We will adopt this guidance beginning in fiscal year 2019. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01 “Business Combinations (Topic 805): Clarifying the Definition of a Business,” which provides a new framework for determining whether transactions should be accounted for as acquisitions

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(or disposals) of assets or businesses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The Partnership adopted this ASU on January 1, 2018, using a prospective method and did not have an impact on the Partnership's unaudited condensed consolidated financial statements and related disclosures.

In October 2016, the FASB issued ASU 2016-16 "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory," which eliminates a current exception in U.S. GAAP to the recognition of the income tax effects of temporary differences that result from intra-entity transfers of non-inventory assets. The intra-entity exception is being eliminated under the ASU. The standard is required to be applied on a modified retrospective basis and is now effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The adoption of ASU 2016-16 did not have an impact on the Partnership's unaudited condensed consolidated financial statements and related disclosures.

In 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 the more timely recognition of losses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019, and earlier adoption is permitted. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02 "Leases (Topic 842)," effective for annual and interim periods for public companies beginning after December 15, 2018. Additionally, in July 2018, the FASB issued ASU 2018-10, "Codification Improvements to Topic 842 (Leases)," which provides narrow amendments to clarify how to apply certain aspects of ASU 2016-02. The Partnership plans on electing 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-to-use asset and lease liability on the statement of financial position for those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee's classification of a finance lease. The Partnership will not early adopt this standard and will apply the revised lease rules for our interim and annual reporting periods starting January 1, 2019. The Partnership has substantially completed its review of the impact of the new standard as well as the implementation of a lease accounting software. Adoption of the standard is expected to result in the recognition of assets and liabilities in our consolidated balance sheets for existing operating leases such as compressors and potentially other equipment still being evaluated. Concurrent with the software implementation, the Partnership is incorporating necessary updates to its business processes and controls. The quantitative impacts of the new standard are dependent on the active leases at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." In March, April, May and December of 2016, the FASB issued rules clarifying several aspects of the new revenue recognition standard. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model requires revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new standard also requires more detailed disclosures related to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The Partnership adopted the standard effective January 1, 2018. For more information, see Note 3 "Revenue Recognition."

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

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying footnotes. These

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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 commodity 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 estimates and judgment. 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 recognize revenue from contracts with customers in accordance with Topic 606 and ASC 840 for our midstream segment. The Seco Pipeline Transportation Agreement is our only contract that we account for using Topic 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 606-10-50-14A(b). 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 840, 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, as we do not currently operate any of our production assets. The Eagle Ford Shale properties are operated by SOG and Marathon Oil Company and the Louisiana properties are operated by SOG. 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. Both revenues and expenses for these arrangements are recognized based on the information provided to us by the operators.

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, 2018 and 2017.

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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 71% and 63% of total revenue for the years ended December 31, 2018 and 2017, 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), 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). Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income (loss) per unit. Undistributed income (loss) is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units. 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, well 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 “Depreciation, depletion, amortization and accretion” in the Partnership’s 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 change to the carrying amount of the liability.

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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, and up to 36 years for gathering facilities.

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 2018 and 2017 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 to the directors of its general partner (for their services as directors) 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.

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Unit-based compensation granted to employees of SOG (including those employees who also serve as the officers of our general partner) and consultants in exchange for services are considered awards to non-employees, and the Partnership records unit-based compensation expense for these awards at fair value in accordance with the provisions of ASC 505-50, "Equity-Based Payments to Non-Employees." For awards granted to non-employees, the Partnership records compensation expenses equal to the fair value of the unit-based award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. Compensation expense for unvested awards to non-employees is revalued at each period end and is amortized over the vesting period of the unit-based award. Unit-based payments are measured based on the fair value of the equity instruments granted, as it is more determinable than the value of the services rendered. In accordance with the guidance, the inclusion of market performance acceleration conditions does not change the accounting classification as compared to those awards without market performance acceleration conditions. Compensation expense for the unvested awards is revalued at each period end and is amortized over the vesting period of the unit-based award.

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 equity earnings (loss) 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 Carnero Gathering's 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

Adoption of Topic 606

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

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

Adoption of this guidance resulted in financial statement presentation changes whereby revenue from the Gathering Agreement and revenue from the Seco Pipeline Transportation Agreement are shown as separate line items within our condensed consolidated statements of operations. There was no cumulative adjustment to retained earnings or any other

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changes to our January 1, 2018 condensed consolidated balance sheet.

Revenue from Contracts with Customers

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

Disaggregation of Revenue

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

Midstream Segment

The Seco Pipeline Transportation Agreement is our only contract that we account for under Topic 606. The Gathering Agreement (as defined in Note 14. "Related Party Transactions") was classified as an operating lease at inception and is accounted for under ASC 840, Leases, and is reported as gathering and transportation lease revenue in our condensed consolidated 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 condensed 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, as we do not currently operate any of our production assets. The Eagle Ford Shale properties are operated by SOG and Marathon Oil Company and the Louisiana properties are operated by SOG. 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. Both revenues and expenses for these arrangements are recognized based on the information provided to us by the operators.

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

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We recognized revenue of $83.6 million for the year ended December 31, 2018. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Year December 31, 2018		
	Production	Midstream	Total
Revenues:			
Natural gas sales	$ 953	$ —	$ 953
Oil sales	21,272	—	21,272
Natural gas liquid sales	1,709	—	1,709
Gathering and transportation sales	—	6,651	6,651
Gathering and transportation lease revenues	—	53,025	53,025
Total revenues	$ 23,934	$ 59,676	$ 83,610

Performance Obligations

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

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

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

Contract Balances

Under our sales contracts, we invoice customers after our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under Topic 606. At January 1, 2018 and December 31, 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.

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Reconciliation of Statements of Operations

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

	Year Ended December 31, 2018		
	As reported	Balances without Adoption Topic 606	Effect of change Higher/(Lower)
Statement of Operations			
Gathering and transportation sales	$ 6,651	$ 59,676	$ (53,025)
Gathering and transportation lease revenues	53,025	—	53,025
Net earnings	$ 59,676	$ 59,676	$ —

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

4. ACQUISITIONS AND DIVESTITURES

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 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. The divestitures were all closed by

May 8, 2018 and we recorded a total gain of approximately $1.1 million on the sale.

Texas Production Divestiture

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

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Non-Operated Production Divestiture

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

Oklahoma Production Divestiture

In May 2017, we entered into a purchase and sale agreement to sell all of the Partnership's equity interests in the entities that owned our remaining Oklahoma production assets for cash consideration of $5.5 million, and assumption by the buyer of all obligations relating to the assets arising after the closing date and all plugging and abandonment costs relating to the assets arising prior to the closing date (the "Oklahoma Production Divestiture"). The Oklahoma Production Divestiture closed July 17, 2017 and we recorded a gain of $2.4 million on the sale.

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. This category includes those derivative instruments that can be valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

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

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, 2018 (in thousands):

Fair Value Measurements at December 31, 2018
Active Markets for Observable

	Identical Assets (Level 1)	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)

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

	Fair Value Measurements at December 31, 2017			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative assets	$ —	$ 1,231	$ —	$ 1,231
Midstream derivative instrument				
Earnout derivative liability	—	—	(6,402)	(6,402)
Total	$ —	$ 1,231	$ (6,402)	$ (5,171)

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

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of ASC 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 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.''

The following table summarizes the non-recurring fair value measurements of our assets and liabilities 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)
Impairment	$ —	$ —	$ —
Total net assets	$ —	$ —	$ —

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

Fair Value Measurements at
December 31, 2017

	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment(a)	$ —	$ —	$ 7,277
Total net assets	$ —	$ —	$ 7,277

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

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

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Fair Value of Financial Instruments

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

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

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

Earnout Derivative – As part of the Carnero Gathering Transaction (defined in Note 12 "Investments"), 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. The earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. We have therefore classified the fair value measurements of our earnout derivative as Level 3 inputs.

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):

	December 31,	
	2018	2017
Beginning balance	$ (6,402)	$ (4,270)
Initial fair value of earnout derivative	—	221
Gain (loss) on earnout derivative	546	(2,353)
Ending balance	$ (5,856)	$ (6,402)
Gain (loss) included in earnings related to derivatives still held as of December 31, 2018 and 2017, respectively	$ 546	$ (2,353)

6. DERIVATIVE AND FINANCIAL INSTRUMENTS

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

Under ASC 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 as realized and unrealized gains (losses) on derivative instruments in the consolidated statements of operations.

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As of December 31, 2018, 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
2019	119,832	$ 2.85	115,784	$ 2.85	112,032	$ 2.85	108,552	$ 2.85	456,200	$ 2.85
2020	105,104	$ 2.85	102,008	$ 2.85	99,136	$ 2.85	96,200	$ 2.85	402,448	$ 2.85
									858,648	

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
2019	62,528	$ 60.41	59,552	$ 60.44	57,024	$ 60.48	54,824	$ 60.52	233,928	$ 60.46
2020	52,776	$ 53.50	50,960	$ 53.50	49,224	$ 53.50	47,624	$ 53.50	200,584	$ 53.50
									434,512	

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, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017
Beginning fair value of commodity derivatives	$ 1,231	$ 6,436
Net gains on crude oil derivatives	1,400	3,284
Net gains (losses) on natural gas derivatives	(84)	663
Net settlements paid (received) on derivative contracts:		
Oil	1,330	(6,422)
Natural gas	37	(2,730)
Ending fair value of commodity derivatives	$ 3,914	$ 1,231

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, 2018	2017
Commodity – Mark-to-Market	Oil sales	$ 1,400	$ 3,284
Commodity – Mark-to-Market	Natural gas sales	(84)	663
		$ 1,316	$ 3,947

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

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Earnout Derivative

Refer to Note 5 “Fair Value Measurements”.

7. LONG-TERM DEBT

Credit Agreement

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

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of $15.0 million which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was $200.0 million. The borrowing base for the credit available for the upstream oil and gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports 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 assets is equal to the rolling four quarter EBITDA of our midstream operations and the amount of distributions received from Carnero JV multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders. As of December 31, 2018, the borrowing base under the Credit Agreement was $310.0 million, with an elected commitment amount of $210.0 million, and we had $180.0 million of debt outstanding under the facility, leaving us with $30.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of December 31, 2018.

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

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

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

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

one-third of total adjusted EBITDA; and

- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of

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

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

At December 31, 2018, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Debt Issuance Costs

As of December 31, 2018 and 2017, our unamortized debt issuance costs were $1.4 million and $1.2 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, 2018 and 2017 were $0.8 million and $0.5 million, respectively.

8. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

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

	December 31,	
	2018	2017
Gathering and transportation assets		
Midstream assets	$ 186,406	$ 184,969
Less: Accumulated depreciation and amortization	(34,598)	(26,870)
Total Gathering and transportation assets, net	$ 151,808	$ 158,099

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

	December 31,	
	2018	2017
Oil and natural gas properties and related equipment		
Proved property	$ 112,173	$ 170,750

Less: Accumulated depreciation, depletion, amortization and impairments	(65,647)	(115,704)
Oil and natural gas properties and equipment, net	$ 46,526	$ 55,046

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

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.

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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, 2018 and 2017 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 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, and up to 36 years for gathering facilities.

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

	Years Ended December 31,	
	2018	2017
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 4,798	$ 9,413

Depreciation and amortization of gathering and transportation related assets	7,729	11,849
Amortization of intangible assets	13,460	13,568
Total Depreciation, depletion and amortization	25,987	34,830
Asset impairments	—	4,688
Total	$ 25,987	$ 39,518

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

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

For the year ended December 31, 2018, we recorded no impairment charges. For the year ended December 31, 2017, we recorded non-cash charges of $4.7 million, to impair certain producing oil and natural gas properties in Texas.

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, and are amortized over proved developed reserves using the units-of-production method. 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, 2018 and 2017.

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, 2018 and 2017 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,	
	2018	2017
Current:		
Federal	$ —	$ —
State	64	—
Total current	64	—

Deferred:		
Federal	—	—
State	126	—
Total deferred	126	—
Total provision for income taxes	$ 190	$ —

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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 before income taxes is as follows (in thousands):

	Years Ended December 31, 2018	2017
Pre-tax net book income (loss)	$ 15,881	$ (3,040)
Texas Margin Tax (a)	267	(438)
Return to accrual	9	—
Valuation allowance	(86)	438
Provision for income taxes	$ 190	$ —
Effective income tax rate	1.20 %	0.00 %

(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, 2018	2017
Deferred tax assets (liabilities):		
Derivative assets	$ (15)	$ 7
Depreciable, depletable property, plant and equipment	(112)	78
Other	1	1
Deferred tax assets (liabilities):	(126)	86
Valuation allowance	—	(86)
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, 2018 and 2017, 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 2015. State statutes vary by jurisdiction.

10. ASSET RETIREMENT OBLIGATION

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

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adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance.

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

	December 31,	
	2018	2017
Asset retirement obligation, beginning balance	$ 6,074	$ 13,579
Liabilities added from escalating working interests	288	198
Sales	(613)	(8,416)
Revisions to cost estimates	(46)	—
Settlements	—	(60)
Accretion expense	497	773
Asset retirement obligation, ending balance	$ 6,200	$ 6,074

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Abandonments of oil and natural gas wells reduce the liability for AROs. In 2018 and 2017, 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 and Louisiana Divestiture and during the year ended December 31, 2017, obligations were sold as part of the Oklahoma Production Divestiture and Texas Production Divestiture.

11. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes $158.7 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 petroleum, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15 year life of the agreement.

Amortization expense for the years ended December 31, 2018 and 2017 was $13.5 million and $13.6 million, respectively. These costs are amortized to depreciation, depletion, and amortization expense in our consolidated statement of operations. Intangible assets as of December 31, 2018 and 2017 are detailed below (in thousands):

	December 31,	
	2018	2017
Beginning balance	$ 172,166	$ 185,766
Disposals	—	(32)
Amortization	(13,460)	(13,568)
Ending balance	$ 158,706	$ 172,166

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 the earnings from equity investments line within the 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

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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, Carnero G&P, LLC ("Carnero JV"), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant ("Silver Oak II"), located in Bee County Texas, to Carnero JV, which expands the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the 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 Comanche acres in the Western Eagle Ford pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the joint ventures 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 Carnero JV using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting, beginning with the three months ended June 30, 2018. The HLBV is a balance-sheet approach that calculates the amount we would have received if Carnero JV were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our consolidated statements of operations. In the event of liquidation of Carnero JV, available proceeds are first distributed to any priority return and unpaid capital associated with Silver Oak II, and then to members in accordance with their capital accounts.

As of December 31, 2018, the Partnership had paid approximately $123.8 million for its investment in Carnero JV related to the initial payments and contributed capital. The Partnership has accounted for this investment using the equity method. Targa is the operator of the joint venture and has significant influence with respect to the normal day-to-day construction and operating decisions. We have included the investment balance in the equity investments caption on our consolidated balance sheets. For the year ended December 31, 2018, the Partnership recorded earnings of approximately $14.0 million in equity investments from 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 $24.9 million were received during the year ended December 31, 2018.

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

Years Ended December 31,	
2019	2018

Sales	$ 321,607	$ 136,178
Total expenses	290,073	118,077
Net income	$ 31,534	$ 18,101

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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 Carnero Gathering's delivery points from Sanchez Energy and other producers. This earnout has an approximate value of $5.9 million and was recorded on the balance sheet as a deferred liability as of December 31, 2018. For the years ended December 31, 2018 and 2017, 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. 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. During the years ended December 31, 2018 and 2017, we incurred costs of approximately $8.6 million and $8.8 million, respectively, to Manager under the Services Agreement. Manager utilizes SOG to provide the services under the Services Agreement.

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. 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, 2017.

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. For the years ended December 31, 2018 and 2017, Sanchez Energy paid us approximately $57.9 million and $52.8 million, respectively, pursuant to the terms of the gathering and processing agreement. On June 30, 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by SN Catarina based on water that is delivered through the gathering system through March 31, 2018. Following March 31, 2018, we have agreed with Sanchez Energy to continue the incremental infrastructure fee on a month-to-month basis.

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, 2018 and 2017, we did not make any earnout payments to Sanchez Energy. However, we had a payable of $0.1 million to Sanchez Energy at year end December 31, 2017 related to the earnout.

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

In September 2017, we entered into the Seco Pipeline Transportation Agreement. For the years ended December 31, 2018 and 2017, SN Catarina paid us approximately $7.2 million and $0.9 million, respectively, pursuant to the terms of that agreement.

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 Comanche acres in the Western Eagle Ford pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Sanchez Energy, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the joint ventures limited by the capacity of the Raptor Gas Processing Facility.

As of December 31, 2018 and 2017, the Partnership had a net receivable from related parties of approximately $6.7 million, and $13.1 million, respectively, which are included in "Accounts receivable – related entities" in the consolidated balance sheets. As of December 31, 2018 and 2017, the Partnership also had a net payable to related parties of approximately $5.6 million, and $10.4 million, respectively. The net receivable/payable as of December 31, 2018 consist primarily of revenues receivable from oil and natural gas production and transportation, offset by costs associated with that production and transportation and ad valorem.

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 473,000 gross leasehold acres (271,000 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 6.5%, 3.2%, 1.2% and 1.3%, respectively, of Sanchez Energy's shares outstanding as of February 26, 2019. As of March 7, 2019, Sanchez Energy indirectly, through one of its wholly owned subsidiaries, beneficially owns approximately 13.0% 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.

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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:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2016	219,144	$ 14.22
Granted	220,814	14.73
Vested	(153,487)	14.20
Returned/Cancelled	(3,333)	13.59
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

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

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

As of December 31, 2018, 1,309,385 common units remain available for future issuance to participants under the LTIP.

16. DISTRIBUTIONS TO UNITHOLDERS

The table below reflects the payment of cash distributions on common units relating to the years ended December 31, 2018 and 2017.

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

The table below reflects the payment of distributions on Class B Preferred Units during the years ended December 31, 2018 and 2017.

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

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

(b) The Partnership elected to pay the second-quarter 2018 distribution on the Class B Preferred Units in part cash and part in Class B Preferred 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.

17. MEMBERS’ EQUITY/PARTNERS’ CAPITAL

Outstanding Units

As of December 31, 2018, we had 31,310,896 Class B Preferred Units outstanding and 16,486,239 common units outstanding, which included 513,694 unvested restricted common units issued under LTIP.

Common Unit Issuances

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

Three months ended	Common units	Date of issuance
September 30, 2016	170,750	March 6, 2017
December 31, 2016	154,737	March 6, 2017
March 31, 2017	139,110	June 30, 2017
June 30, 2017	170,497	August 31, 2017
September 30, 2017	186,942	November 30, 2017
December 31, 2017	210,978	March 15, 2018
March 31, 2018	220,214	May 31, 2018
June 30, 2018	224,342	September 10, 2018
September 30, 2018	334,010	November 30, 2018

In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately $1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015 as updated by that certain prospectus supplement filed with the SEC on April 6, 2017 (the “Shelf Registration Statement”). The Shelf Registration Statement allows the Partnership to sell up to $50.0 million of common units by any method deemed an “at the market offering” (as such term is defined in Rule 415 of the Securities Act of 1933, as amended). Proceeds from such sales are expected to be used to fund general limited partnership purposes, including possible acquisitions. Proceeds from the 2017 at-the-market equity issuance were used for general limited partnership purposes.

Class B Preferred Unit Offering

On October 14, 2015, pursuant to that certain Class B Preferred Unit Purchase Agreement dated September 25, 2015 between the Partnership and Stonepeak, 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

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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 acquisition of Western Catarina Midstream, along with the payment to Stonepeak of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

Under the terms of our partnership agreement, holders of the Class B Preferred Units receive a quarterly distribution, at the election of the Board, of 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 are to be paid on or about the last day of each of February, May, August and November after the end of each quarter.

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

The 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,	
	2018	2017
Mezzanine equity, beginning balance	$ 343,912	$ 342,991
Amortization of discount	2,358	1,796
Distributions	36,925	35,875
Distributions paid	(33,338)	(36,750)
Mezzanine equity, ending balance	$ 349,857	$ 343,912

Earnings per Unit

Net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income (loss), 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).

Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income (loss) per unit. Undistributed income (loss) is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units. 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

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of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

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

18. REPORTING SEGMENTS

"Midstream" and "Production" best describe the operating segments of the businesses that we separately report. The factors used to identify these reportable 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 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.

We realigned the composition of our operating segments to reflect management's view of the operating results during the fourth-quarter 2017. The following tables present financial information for each operating segment for the periods indicated based on the realignment of our operating segments (in thousands):

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	Years Ended December 31,			
	2018		2017	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 953	$ —	$ 6,626	$ —
Oil sales	21,272	—	23,701	—
Natural gas liquid sales	1,709	—	1,997	—
Gathering and transportation sales	—	6,651	—	55,825
Gathering and transportation lease revenues	—	53,025	—	—
Total segment revenues	23,934	59,676	32,324	55,825
Segment operating costs				
Lease operating expenses	6,719	1,145	12,066	928
Transportation operating expenses	—	12,316	—	11,600
Cost of sales	—	—	77	—
Production taxes	1,104	—	1,476	—
Gain on sale of assets	(3,186)	—	(4,150)	—
Depreciation, depletion and amortization	4,798	21,189	9,522	25,308
Asset impairments	—	—	4,688	—
Accretion expense	198	299	499	274
Total segment operating costs	9,633	34,949	24,178	38,110
Segment other income (loss)				
Earnings (loss) from equity investments	—	12,859	(101)	7,986
Total segment other income (loss)	—	12,859	(101)	7,986
Segment operating income	$ 14,301	$ 37,586	$ 8,045	$ 25,701

	Years Ended December 31,	
	2018	2017
Reconciliation of segment operating income to net income (loss)		
Total production operating income	$ 14,301	$ 8,045
Total midstream operating income	37,586	25,701
Total segment operating income	51,887	33,746
General and administrative expense	(23,653)	(22,655)
Unit-based compensation expense	(1,938)	(3,373)
Interest expense, net	(10,961)	(8,341)
Other income (expense)	546	(2,417)
Income tax expense	(190)	—

Net income (loss)	$ 15,691	$ (3,040)

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

	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

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

(a) Corporate assets not reviewed by the CODM on a segment basis consists of cash, certain prepaid expenses, office furniture and other assets.

(b) Inclusive of capital contributions made to equity method investments.

The following table summarizes the percentage of revenue earned from those customers in the Midstream segment that exceed 10% of the Partnership's consolidated revenue for the periods presented below. 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.

	Years Ended December 31,	
	2018	2017
Midstream		
Sanchez Energy	71 %	63 %
Total	71 %	63 %

19. VARIABLE INTEREST ENTITIES

The Partnership's investment in 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 Carnero JV is limited to the capital investment of approximately $114.5 million.

As of December 31, 2018, the Partnership had invested approximately $123.8 million in Carnero JV and no debt has been incurred by Carnero JV. We have included this VIE in the equity investments long-term asset line on the balance sheet.

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

	December 31,	
	2018	2017
Acquisitions and capital investments	$ 127,899	$ 125,059
Earnings in equity investments	23,144	10,288
Distributions received	(36,578)	(11,632)
Maximum exposure to loss	$ 114,465	$ 123,715

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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, 2018 and 2017 (in thousands):

	December 31, 2018	2017
Capitalized costs at the end of the period:		
Oil and natural gas properties and related equipment (successful efforts method)		
Proved property	$ 112,173	$ 170,750
Less: Accumulated depreciation, depletion, amortization and impairments	(65,647)	(115,704)
Oil and natural gas properties and equipment, net	$ 46,526	$ 55,046

(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, 2018 and 2017 (in thousands):

	Years Ended December 31, 2018	2017
Costs incurred for the period:		
Acquisition of properties		
Proved	$ —	$ —
Development costs	11	441
Oil and natural gas properties and equipment, net	$ 11	$ 441

The development costs for the years ended December 31, 2018 and 2017 primarily represent costs related to recompletions.

We had no exploration and dry hole costs in 2018 and 2017.

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.

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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, 2016	6,870	3,514	2,426	930
Sales of reserves in place	(1,731)	(358)	(1,280)	(93)
Revisions of previous estimates	1,062	504	383	175
Production	(936)	(414)	(420)	(102)
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
Proved developed reserves:				
December 31, 2017	5,265	3,246	1,109	910
December 31, 2018	3,453	2,479	454	520

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, 2018 and 2017, proved reserve estimates were 3.5 MMBoe and 5.3 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 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.

Our 2017 estimates of total proved reserves decreased 1.6 MMBoe from 2016 primarily due to a decrease in reserves of 1.7 MMBoe due to the Oklahoma Production Divestiture and Texas Production Divestiture. For proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $48.69 per Bbl for oil, $21.34 per Bbl for NGLs and $3.04 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.

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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,	
	2018	2017
Future cash inflows	$ 186,675	$ 197,739
Future production costs	(99,187)	(101,300)
Future estimated development costs	(4,043)	(4,346)
Future net cash flows	83,445	92,093
10% annual discount for estimated timing of cash flows	(31,199)	(35,396)
Standardized measure of discounted estimated future net cash flows related to proved oil and natural gas reserves	$ 52,246	$ 56,697

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,	
	2018	2017
Beginning of the period	$ 56,697	$ 49,636
Sales and transfers of oil and natural gas, net of production costs	(14,795)	(14,758)
Net changes in prices and production costs related to future production	17,392	15,036
Changes in development costs	207	3,854
Changes in extensions and discoveries	—	160
Revisions of previous quantity estimates	(4,203)	9,137
Purchases and sales of reserves in place	(5,423)	(11,952)
Accretion discount	5,670	4,964
Change in production rates, timing, and other	(3,299)	620
Standardized measure of discounted future net cash flows related to proved oil and natural gas reserves	$ 52,246	$ 56,697

21. SUBSEQUENT EVENTS

On February 7, 2019, the Board declared a fourth-quarter 2018 cash distribution on its common units of $0.15 per unit ($0.60 per unit annualized), which was paid on February 28, 2019 to holders of record on February 20, 2019. The Partnership also declared a fourth-quarter 2018 cash distribution on the Class B Preferred Units of $0.28225 per Class B Preferred Unit, which was paid on February 28, 2019 to holders of record on February 20, 2019.

On February 22, 2019, the Partnership paid $2.0 million in principal outstanding under the Credit Agreement resulting in debt outstanding of $178.0 million under the Credit Agreement as of that date.

Effective January 1, 2019, the Partnership increased the Western Catarina Midstream tariff rate for throughput volumes from approximately 71,000 net acres on Sanchez Energy's Catarina Asset which are not currently dedicated under the Gathering Agreement.