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, 2015
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 Production 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 Class B Limited Liability Company Interests	NYSE MKT LLC

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☒

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 Production Partners LP Common Units, without par value, held by non-affiliates as of June 30, 2015 was approximately $56,025,082 based upon NYSE MKT closing price.

Common Units outstanding on March 30, 2016: 3,031,051 common units.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains “forward-looking statements” as defined by the 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;
- acquisition strategy;
- financial strategy;
- 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 and processing agreements;
- future operating results;
- future capital expenditures; and
- plans, objectives, expectations, forecasts, outlook and intentions.

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on 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. Management cautions all readers that the forward-looking statements contained in this Annual Report on 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 Annual Report on 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.

COMMONLY USED DEFINED TERMS

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

- "Sanchez Production Partners," "the Partnership," "we," "us," "our" or similar references mean Sanchez Production Partners LP and its consolidated subsidiaries. Such terms also refer to Sanchez Production Partners LLC, our predecessor-in-interest prior to our conversion from a limited liability company to a limited partnership.
- "Bbl" means a barrel of 42 U.S. gallons of oil.
- "Bcf" means one billion cubic feet of natural gas.
- "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.
- "Manager" refers to SP Holdings, LLC, the sole member of our general partner.
- "Bcfe" means one billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs.
- "Mcf" means one thousand cubic feet of natural gas.
- "MBoe" means one thousand barrels of oil equivalents.
- "MBbl" means one thousand barrels of crude oil or other liquid hydrocarbons.
- "MMBbl" means one million barrels of crude oil or other liquid hydrocarbons.
- "MMBoe" means one million barrels of oil equivalent.
- "MMBtu" means one million British thermal units.
- "MMcf/d" means one million cubic feet of natural gas per day.
- "NGLs" means natural gas liquids.
- "our general partner" refers to Sanchez Production Partners GP LLC, our general partner.
- "Sanchez Energy" refers to Sanchez Energy Corporation and its consolidated subsidiaries.
- "SOG" refers to Sanchez Oil & Gas Corporation.

PART I

Item 1. Business

Overview

We were formed in 2005 as a Delaware limited liability company until our conversion on March 6, 2015 into a Delaware limited partnership. We are focused on the acquisition, development, ownership and operation of midstream and other energy producing assets. Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale (the "Catarina gathering system") from Sanchez Energy and entered into a 15-year gathering and processing agreement with Sanchez Energy (the "Catarina gathering and processing agreement").

We have entered into a shared services agreement (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, professionals and acquisition, disposition and financing services.

Our common units are currently listed on the NYSE MKT under the symbol "SPP."

Our Relationship with Sanchez Energy, Manager and SOG

We believe that our relationship with Sanchez Energy provides us with growth opportunities through Sanchez Energy selling additional assets to us over time and facilitating organic growth opportunities and accretive acquisitions from other third parties. Sanchez Energy is currently a high-quality anchor customer for the Catarina gathering system. According to its filings with the SEC, Sanchez Energy had as of December 31, 2015, approximately 200,000 net leasehold acres in the oil and condensate windows of the Eagle Ford Shale in Texas, with total proved reserves of 128 MMBoe, including 85 MMBoe in the dedicated acreage subject to the Catarina gathering and processing agreement. In addition, pursuant to a right-of-first-offer, Sanchez Energy has agreed to provide us the first right to make an offer to purchase any midstream assets and reversionary working interests that it desires to sell, although there can be no assurance that we would be able to acquire any such assets on terms reasonably acceptable to us, or at all. 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. We do not have a current agreement or understanding with Sanchez Energy to purchase any assets covered by our right-of-first-offer.

We believe that our relationship with Manager will provide us with competitive advantages operationally. Manager is the sole member of our general partner and has an interest in us through its ownership of all of our incentive distribution rights. Pursuant to the Services Agreement, Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services, in exchange for a quarterly fee, the reimbursement of all allocated overhead costs as well as any direct third-party costs incurred and a fee for each asset acquisition, asset disposition and financing.

Manager utilizes SOG to provide the services under the Services Agreement. SOG has a senior management team that averages over 20 years of industry experience and employs over 200 full-time employees, including 46 technical staff and engineers. SOG has a dedicated business development team that screens approximately 150 acquisition opportunities per year.

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

Although we believe that our relationships with SOG and Sanchez Energy provide us with a significant advantage in acquiring assets in the midstream and producing asset markets, there is no assurance that we will achieve such an advantage or otherwise benefit as a result of these relationships. While our relationships with SOG, Sanchez Energy and its subsidiaries is a significant strength, it also is a source of potential conflicts. Please read “Risk Factors.”

Business Strategy

Our primary business objective is to create long-term value and to generate stable cash flows that allow us to make and grow distributions over time. We plan to achieve our objective by executing our business strategy, which is to:

- Conduct a sales process to evaluate and pursue the possible divestiture of our Mid-Continent assets in 2016;
- Align our asset base, interests and operations with our sponsor, SOG;
- Grow our business by acquiring cash producing assets involved in production, gathering and processing activities with minimal maintenance capital requirements and low overhead; and
- Reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs.

Business Segments

Our business activities are conducted by two operating segments for which we provide information in our consolidated financial statements for the years ended December 31, 2015 and 2014. These two segments are our:

- midstream business, which includes the Catarina gathering system; and
- exploration and production business, which includes oil and natural gas reserves located in the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana, as well as properties in the Mid-Continent region.

For information about our segments’ revenues, profits and losses and total assets, see Note 15. “Reporting Segments” of our Notes to Consolidated Financial Statements.

Midstream Business

Catarina Gathering System

In October 2015, we acquired the Catarina gathering system from Sanchez Energy. The system consists of gathering assets, pipelines, processing units, compression units and other related assets in Western Catarina, which are located in Dimmit and Webb Counties, Texas and service upstream production from the Eagle Ford Shale. The Catarina gathering system consists of approximately 150 miles of gathering lines, compressors, tanks, vessels and other miscellaneous production infrastructure. The gathering pipelines range in diameter from 4 to 12 inches, with capacity of 40,000 barrels per day for crude oil and NGLs, and 200 MMcf/d for natural gas. There are four main gathering and processing facilities, which include eight stabilizers of 5,000 barrels per day, approximately 25,000 barrels of storage capacity, NGL pressurized storage, approximately 18,000 horsepower of compression and approximately 300 MMcf/d of dehydration capacity. The gathering system is used solely to support the gathering, processing and transportation of crude oil, NGLs and natural gas produced by Sanchez Energy in the Western Catarina. The gathering system has crude 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 it has natural gas interconnects with Southcross Energy, Kinder Morgan, Energy Transfer and Transwestern

Pipeline. Pipeline capacity on the gathering system can be expanded through small compression projects at a nominal cost, with approximately $1.0 million in capital expenditures planned per year.

During the fiscal year ended December 31, 2015, Sanchez Energy transported average daily production through the gathering system of approximately 4,272 Bbls of crude oil and 9,221 Boe of natural gas. The average age of the Catarina gathering system assets is approximately 5 years, and they have an expected life of approximately 25 more years.

Customer

Our midstream business has one customer, Sanchez Energy, as a result of having entered into the Catarina gathering and processing agreement. All of the revenue from the Catarina gathering system are currently earned under this agreement. Pursuant to the 15-year agreement, Sanchez Energy tenders all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through the gathering system, with a right to tender additional volumes outside of the dedicated acreage. During the first five years of the term (or through 2020), Sanchez Energy has agreed to tender a minimum quarterly volume of 10,200 barrels per day of crude oil and NGLs and 142,000 Mcf per day of natural gas in the dedicated acreage. Sanchez Energy is required to pay us gathering and processing fees of $0.96 per barrel for crude oil and condensate produced and $0.74 per Mcf for natural gas that are tendered through the Catarina gathering system, in each case, subject to an annual escalation for a positive increase in the consumer price index. After the end of the 15 year agreement, the rate will be subject to renegotiation between the parties. Except for a force majeure or temporary shutdown for testing and maintenance, we are obligated to transport all crude petroleum or other hydrocarbon-based products tendered by Sanchez Energy on the Catarina gathering system for shipment up to the minimum volume per day that Sanchez Energy is required to tender.

Title to Properties

Title to the gathering system assets falls into two categories: parcels that are owned in fee and parcels in which our interest is derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which portions of the gathering system are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remaining land on which the gathering system is located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. Our predecessors leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands. 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 that have, and we believe that we have satisfactory title to all of the material leases, easements, rights-of-way, permits and licenses with respect to the Catarina gathering system.

Exploration and Production Business

Our total estimated proved reserves at December 31, 2015, were approximately 11.6 MMBoe, approximately 99% of which were classified as proved developed, with 67% being natural gas, 6% being NGLs, and 27% being oil. At December 31, 2015, we owned approximately 1,992 net producing wells. Our total average proved reserve-to-production ratio is approximately 8.1 years and our portfolio decline rate is 12% to 24% based on our estimated proved reserves at December 31, 2015 and production for the month ended December 31, 2015.

Below is a description of our operations and our oil and natural gas properties by basin at December 31, 2015:

Locations

We have oil and gas properties in three basins in the Mid-Continent region of the United States:

- Cherokee Basin, where we had approximately 6.6 MMBoe of estimated proved reserves at December 31, 2015, approximately 98% of which were classified as proved developed, with 93% being natural gas and 7% being oil;
- Woodford Shale, where we had approximately 84 MBoe of estimated proved reserves at December 31, 2015, all of which were classified as proved developed and natural gas; and
- Central Kansas Uplift, where we had approximately 30 MBoe of estimated proved reserves at December 31, 2015, all of which were classified as proved developed, with 7% being natural gas and 93% being oil.

In addition, we own properties in the onshore Texas and Louisiana Gulf Coast Region, where we had approximately 4.8 MMBoe of estimated proved reserves at December 31, 2015, all of which were classified as proved developed, with 30% being natural gas, 15% being NGLs, and 55% being oil.

Operations

We do not operate any of our oil and gas properties, except in the Cherokee Basin where we operate a substantial portion of our properties. In the Woodford Shale, approximately 95% of the wells are operated by affiliates of Linn Energy LLC and Newfield Exploration Mid-Continent, Inc., with the remaining wells operated by three additional companies. Murfin Drilling Company, Inc., an experienced oil producer in Kansas, operates all of our wells in the Central Kansas Uplift. Zachry Exploration, LLC operates assets located in onshore southern Louisiana, with the remaining wells in Texas being operated by SOG.

Proved Oil, Natural Gas and Natural Gas Liquids Reserves

The following table reflects our estimates of proved oil, natural gas and NGLs 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 oil and NGLs.

Reserve data:	**2015**	**2014**
Estimated proved reserves:		
Oil (MMBbl)	3.2	1.7
Natural gas (Bcf)	46.4	89.5
Natural gas liquids (MMBbl)	0.7	0.1
Total proved reserves (MMBoe)	11.6	16.6
Estimated proved developed reserves:		
Oil (MMBbl)	3.1	1.6
Natural gas (Bcf)	46.2	65.2
Natural gas liquids (MMBbl)	0.7	0.1
Total proved developed reserves (MMBoe)	11.5	12.4
Estimated proved undeveloped reserves:		
Oil (MMBbl)	0.1	0.1
Natural gas (Bcf)	0.2	24.3
Natural gas liquids (MMBbl)	—	—
Total proved undeveloped reserves (MMBoe)	0.1	4.2
Proved developed reserves as a percent of total reserves	99%	75%
Standardized Measure (in millions)[(a)]	$ 67.9	$ 119.5

(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.

Our 2015 estimates of total proved reserves decreased 5.1 MMBoe from 2014 due to a 24.1 Bcf decrease in undeveloped gas reserves in the Cherokee Basin. The higher volumes in 2014 were due to a higher gas price. Our reserves are 67% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. For the proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report are $50.28 per barrel for oil, $19.90 per barrel for NGLs and $2.58 per Mcf for natural gas.

We have a successful track record of developing our proved undeveloped reserves. We do not rely on any proprietary technology to drill our development wells. Based on our organizational structure and our current business plans, our forecasted cash flow over the next five years is expected to be sufficient to fund this type of development drilling program on certain of our proved undeveloped locations. Using the SEC guidelines for estimating proved reserves, all of the locations are scheduled to be drilled within the next five years.

The following table summarizes our inventory of proved undeveloped locations as of December 31, 2015:

	Year PUD Is Scheduled To Be Developed				
	2016	**2017**	**2018**	**2019**	**2020**
Number of Locations	3	—	—	—	1
Equivalents-MBoe	91.7	—	—	—	27.0
Capital Estimate-$millions	$ 0.8	$ —	$ —	$ —	$ 0.3

As of December 31, 2015, we identified 4 gross and net proved undeveloped drilling locations, all of which were identified and economically viable at December 31, 2014. The table below details the activity in our PUD locations from December 31, 2014 to December 31, 2015:

	Gross Locations	**Net Locations**	**Net Volume (MMBoe)**
Balance as of December 31, 2014	300	246	4.2
PUDs converted to PDP by drilling	—	—	—
PUDs removed due to performance	—	—	—
PUDs removed from future drilling schedule	296	242	4.1
Acquisition activity	—	—	—
Extension & discovery	—	—	—
Revisions	—	—	—
Balance as of December 31, 2015	4	4	0.1

Excluding acquisitions, we expect to make capital expenditures related to drilling and completion of wells of approximately $0.8 million during the year ending December 31, 2016. No PUDs were removed in 2015 due to performance issues. 296 PUDs were removed from the future drilling schedule in 2015 due to lower oil and natural gas prices. No locations are included that would generate positive future net revenue but have negative present worth when discounted at 10 percent.

At December 31, 2015 and 2014, Netherland, Sewell & Associates, Inc. (“NSAI”) and Ryder Scott Co. LP (“Ryder Scott”), independent oil and natural gas engineering firms, prepared estimates of all our proved reserves. We used NSAI’s and Ryder Scott’s estimates of our proved reserves to prepare our financial statements. NSAI and Ryder Scott maintain a degreed staff of highly competent technical personnel. The average experience level of NSAI’s technical staff of engineers, geoscientists and petro physicists exceeds 20 years, including 5 to 15 years with a major oil company. The engineering information presented in Ryder Scott’s report was overseen by Don P. Griffin, P.E. Mr. Griffin is an experienced reservoir engineer having been a practicing petroleum engineer since 1976. He has more than 30 years of experience in reserves evaluation with Ryder Scott. Our technical staff of engineers and geosciences professionals has an average experience level that exceeds 27 years. Our activities with NSAI are coordinated by a reservoir engineer employed by us who has approximately 35 years of experience in the oil and natural gas industry and an engineering degree from the University of Tennessee and a masters 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 NSAI and Ryder Scott prior to review by the audit committee of the board of directors of our general partner and approval by the board of directors of our general partner.

Production and Price History

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

	For the Year Ended December 31,	
	2015	2014
Net Production:		
Natural gas production (MMcf)	5,986	6,911
Oil production (MBbl)	331	286
Natural gas liquids production (MBbl)	100	71
Total production (MBoe)	1,428	1,509
Average daily production (Boe/d)	3,913	4,134
Average Sales Prices:		
Natural gas price per Mcf with hedge settlements	$ 3.23	$ 4.80
Natural gas price per Mcf without hedge settlements	$ 2.03	$ 3.69
Oil price per Bbl with hedge settlements	$ 88.65	$ 91.90
Oil price per Bbl without hedge settlements	$ 48.79	$ 92.14
Liquid price per Bbl without hedge settlements	$ 16.03	$ 34.89
Total price per BOE with hedge settlements	$ 35.18	$ 41.05
Total price per BOE without hedge settlements	$ 20.92	$ 36.00
Average Unit Costs Per BOE:		
Field operating expenses[a]	$ 15.18	$ 16.05
Lease operating expenses	$ 13.93	$ 13.93
Production taxes	$ 1.25	$ 2.12
General and administrative expenses	$ 18.28	$ 10.93
Depreciation, depletion and amortization	$ 10.18	$ 11.62
Asset impairments	$ 86.72	$ 3.59

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

Productive Wells

The following table sets forth information at December 31, 2015, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of producing commercial quantities of oil or natural gas, including oil and natural gas wells awaiting pipeline connections to commence deliveries.

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		Oil	
	Gross	Net	Gross	Net
Operated	1,533	1,501	196	194
Non-operated	552	245	132	52
Total	2,085	1,746	328	246

We did not convert any proved undeveloped wells into proved producing wells in 2015. We had estimated a total of 17 wells scheduled to be converted from the 2014 reserve report. Previously, our focus for capital expenditures was on exploration and development of properties, but it shifted into an acquisition-based approach focusing primarily on producing developed properties to generate stable cash flows under the master limited partnership format.

Drilling Activity

The following table sets forth information with respect to oil and natural gas wells drilled and completed by us during the years ended December 31, 2015 and 2014. 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, 2015 or 2014.

	Year Ended December 31,		Wells in Progress at December 31,
	2015	2014	2015
Gross:			
Development			
Productive	1	11	—
Dry	—	—	—
Recompletions	—	6	—
Total	1	17	—
Net:			
Development			
Productive	—	8	—
Dry	—	—	—
Recompletions	—	6	—
Total	—	14	—

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2015 related to our leasehold acreage.

	Developed Acreage[(a)]		Undeveloped Acreage[(b)]	
	Gross[(c)]	Net[(d)]	Gross[(c)]	Net[(d)]
Total	229,863	210,821	16,035	12,844

(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

Our leases are concentrated in Oklahoma (85%), Texas (6%), Kansas (8%) and Louisiana (1%). We have approximately 1,537 leases in the Cherokee Basin on 224,300 gross acres, or approximately 215,252 net acres. Our acreage includes areas leased under a concession agreement that we have with the Osage Nation in Osage County, Oklahoma, which provides us with the exclusive right to lease for coalbed methane on up to 560,000 acres within Osage County and the exclusive right for a period of 90 days after drilling a coalbed methane well on any such acreage to lease for oil and natural gas on such acreage. Generally, we have the right each year to elect to license up to a certain amount of acreage under the concession agreement for such year for a specified license payment, and a license must be obtained before we then lease the acreage. During the term of the concession agreement, however, we have the exclusive right to lease the acreage covered thereunder for coalbed methane unless we notify the Osage Nation in writing that we have no intention to lease any particular acreage. Our concession agreement with the Osage Nation requires drilling and completing a specified number of wells between 2005 and 2020, which we had achieved as of December 31, 2012, the most recent drilling target. We believe that the Osage Nation has granted at least two concessions for the drilling of conventional oil and natural gas on acreage which overlaps certain of the acreage covered by our earlier granted concession, and it has taken the position that we are not entitled to conventional oil and natural gas leases under the terms of our concession agreement where we have not drilled a coalbed methane well first.

The typical oil and natural gas lease agreement covering our other Cherokee Basin properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on or pooled with the leased property. In the Cherokee Basin, depending on the location of a particular well, the total lease burden on our operated properties is generally 20%, generally corresponding to an 80% net revenue interest to us, and on our non-operated properties is generally a 40% net revenue interest. We have approximately 58 leases with a gross acreage position of 3,710 acres, or approximately 893 net acres in the Central Kansas Uplift. We have no leasehold rights associated with our 83 well bores in the Woodford Shale. We have approximately 92 leases in Louisiana with a gross acreage position of 3,318 acres, or approximately 658 net acres. We have approximately 315 leases in Texas with a gross acreage position of 14,570 acres, or 6,862 net acres.

Under the oil and natural gas lease agreements covering our productive wells, such leases have generally been perpetuated beyond their stated lease term and generally will not expire unless and until associated production ceases. Such leases are said to be “held by production” and do not require us to make lease payments beyond the royalty amount stipulated by each lease. The area held by production from a particular well is typically held by lease or applied to a pooled unit for such well or as specified under state law. Barring establishment of commercial production, most of our leases not currently held by production will expire. Approximately 12% and 7% of our total net undeveloped acreage of 12,844 acres is held under leases that have remaining primary terms expiring in 2016 and 2017, respectively. Of these expiration amounts in 2016 and 2017, approximately 83% and 95%, respectively, apply to our concession agreement with the Osage Nation. If these leases do expire, we have the exclusive right to acquire a new coalbed methane lease on any expired acreage under our concession agreement with the Osage Nation until its expiration in 2020 or any earlier termination according to its terms and conditions. The remaining expiring acreage in all three years is primarily located in Kansas and Oklahoma.

Marketing and Major Customers

We manage our oil and natural gas marketing efforts and actively monitor our credit exposure to our major customers. We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC; Keystone Gas Corporation; Scissortail Energy, LLC; Cotton Valley Compression, L.L.C.; Cherokee Basin Pipeline, LLC and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals L.P. and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production in the Central Kansas Uplift is marketed by the operators of our properties. Our natural gas and oil production in the onshore Texas and Louisiana Gulf Coast region is marketed by the operators of our properties.

Title to Properties

When we acquire our interests in oil and natural gas properties, we obtain a title opinion or perform a review on the most significant leases in the fields. As a result, title opinions or reviews have been obtained on a significant portion of our properties. In some instances, and as is customary in our industry, we conduct only a cursory review of the title to certain properties on which we do not have proved reserves. To the extent title opinions or other investigations reflect title requirements on those properties, we are typically responsible for curing any material title matters at our expense. We generally will not commence drilling operations on a property until we have cured or waived any such title matters or deemed the title risk sufficiently mitigated to justify proceeding with operations on the property.

We believe that we have satisfactory title to all of our material oil and gas properties. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry. We believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties to operate our exploration and production business.

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil 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 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 other customers besides Sanchez Energy for the Catarina gathering system, 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.

We are also affected by competition for drilling rigs, completion rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which has delayed development drilling activities and has caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development and drilling program. To date, however, we have not experienced such shortages. In addition, over the past several years, our field employees have been working with teams of drilling and completion contractors and have developed relationships that should enable us to mitigate the risks associated with equipment availability.

Neither SOG nor any of its related companies are restricted from competing with us.

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. Under the auspices of the federal Environmental Protection Agency ("EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters 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, imposes 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 include the owner or operator 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, for damages to natural resources and for 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.

We currently own, lease or operate numerous properties that have been used for oil and natural gas exploration and production for a number of years. Although we believe that operating and waste disposal practices utilized in the past with respect to these properties were typical for the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was 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 contamination.

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 was enacted in 1990 to amend 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. In particular, the regulations developed under the Oil Pollution Act strengthened the requirements that apply to Spill Prevention, Control and Countermeasure Plans. 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, finalized rules that lower the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 parts per billion ("ppb") to 70 ppb. In addition, in September 2015, the EPA proposed rules which defined what are called "stationary sources" to resolve how sources of emissions from the crude oil and natural gas sector should be aggregated under Clean Air Act permit programs. Compliance with these or other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. Compliance with these rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. 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”), the prospect for adoption of significant legislation at the federal level to reduce GHG emissions is perceived to be low at this time. Nevertheless, the Obama Administration has announced that it intends to adopt additional regulations to reduce emissions of GHGs and to encourage greater use of low carbon technologies. In January 2015, the Administration announced that the EPA plans to propose new regulations that will set methane emission standards for new and modified oil and gas production and gas processing and transmission facilities to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Furthermore, in August 2015, the EPA issued final rules outlining the Clean Power Plan (“CPP”), which was developed in accordance with the Administration’s Climate Action Plan announced the previous year. Under the CPP, carbon pollution from power plants must be reduced over 30% below 2005 levels by 2030. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are our customers, which could thereby reduce demand for our midstream services. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, it is uncertain if they would have an adverse effect on our financial condition and operations.

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 commenced a study of the potential environmental impacts of hydraulic fracturing activities. In 2014, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act of 1976 requesting comments related to disclosure for hydraulic fracturing chemicals. Further, the Department of the Interior has released final regulations governing hydraulic fracturing on federal and Native American 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 Endangered Species Act (“ESA”), and analogous state laws, restrict activities that may affect listed endangered or threatened species or their habitats. If endangered species are located in areas where we operate, our operations or any work performed related to them could be prohibited or delayed or expensive mitigation may be required. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in compliance with the ESA. In addition, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to review and consider the listing of numerous species as endangered under the ESA by no later than the completion of the agency’s 2017 fiscal year.

Additional listings under the ESA and similar state laws could result in the imposition of restrictions on our operations and consequently have an adverse effect on our business.

Gathering System Regulation

Regulation of pipeline gathering services 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 and service conditions, 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 is 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 as a natural gas company 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 as a natural gas company. 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 consider the status of an individual gathering facility and determine that the facility and/or services provided by it are not exempt from FERC regulation, the rates for, and terms and conditions of, services provided by such facility 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 our results of operations and cash flows. In addition, 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 service, 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 systems have not been regulated by the FERC as a natural gas company 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 civil penalties of up to $1,000,000 per day for violations of the NGA and increases the FERC's civil penalty authority under the Natural Gas Policy Act ("NGPA") from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. In Order No. 670, the FERC promulgated rules implementing the anti-market manipulation provision of the EPAct 2005. The rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to: (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

Pipeline Safety Regulation

We are subject to regulation by the United States Department of Transportation ("DOT") under the Hazardous Liquid Pipeline Safety Act of 1979 ("HLPSA") and comparable state statutes with respect to design, installation, inspection, testing, construction, operation, replacement and maintenance of pipeline facilities. HLPSA 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 gas pipelines are subject to regulation by Pipelines and Hazardous Materials Safety Administration ("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 Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the U.S. 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 HCAs. For example, effective October 25, 2013, PHMSA finalized rules that increased the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after January 2012 to $200,000 per violation per day, with a maximum of $2,000,000 for a series of violations.

PHMSA regularly revises its pipeline safety regulations and has published advanced notices of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including whether to extend the integrity management program requirements to previously unregulated gathering lines. In 2015 and 2014, PHMSA issued advisory bulletins providing guidance on actions pipeline operators should consider taking to ensure the integrity of pipelines in the event of severe flooding or hurricane damage, notice of construction, flow reversal procedures, product changes and conversion, integrity management program evaluation metrics, and incident response plans. Further changes to PHMSA's rules are expected in the future.

For example, in September 2014, the Government Accountability Office ("GAO") released a report in which the GAO recommended that PHMSA propose a rulemaking to address safety risks, including emergency response planning, from large-diameter, high-pressure gathering lines due to the recent increase in their size and operating pressures. In addition, in July 2014, the EPA's Office of Inspector General recommended that the EPA work with PHMSA to address methane leaks from a combined environmental and safety perspective, and also develop a strategy to address the financial and policy barriers that hinder further methane reductions from the transmission and distribution sectors. In January 2015, the EPA unveiled a plan to cut methane emissions from the oil and gas sector by 40 to 45 percent by 2025, using 2012 methane emissions as a baseline. To implement that plan, in September 2015, the EPA issued a proposed rule to amend new source performance standards for the oil and natural gas source category by setting standards for both methane and volatile organic compounds for certain equipment, processes, and activities across the source category, including equipment and processes at gas gathering facilities. Also as part of that plan, the EPA called for PHMSA to propose new standards and programs to reduce methane leaks from natural gas transportation and distribution lines. Moreover, on In July 2015, PHMSA issued a notice of proposed rulemaking proposing, inter alia, to extend operator qualification requirements to operators of certain gas gathering lines. 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. While we cannot predict the outcome of legislative or regulatory initiatives, such regulatory changes and any legislative changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations.

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

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

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

Other Laws and Regulation

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

Our operations in Texas are subject to the rules and regulations of the Railroad Commission of Texas, Oil & Gas Division. Our operations in Louisiana are subject to the rules and regulations of the Louisiana Department of Natural Resources, Office of Conservation. We believe that we are in substantial compliance with these rules and regulations.

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, 2015, 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

Pursuant to the Services Agreement, 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 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.

As of March 28, 2016, our subsidiary, CEP Services Company, Inc., had 48 employees, all of whom, solely supported the operation of our oil and gas properties in the Mid-Continent region and were full-time employees.

As of March 28, 2016, 8 employees were employed by SOG with their primary function being to provide services for us. Of these employees, 7 were full-time employees.

None of our or SOG’s employees are subject to a collective bargaining agreement.

Offices

We are headquartered in Houston, Texas. We also own and maintain field offices in Coffeyville, Kansas and Skiatook, Oklahoma in connection with the operation of our Mid-Continent region properties.

Available Information

Our internet address is http://www.sanchezpp.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 Annual Report on 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. The public may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 723-0330.

Item 1A. Risk Factors

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. The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates or expectations contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

The risk factors in this report are grouped into the following categories:

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

Risks Related to Our Midstream Business

Because all of our revenue relating to the operation of the Catarina gathering system is expected to be 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.

We are substantially dependent on Sanchez Energy as our only current customer for utilization of the Catarina gathering system, and we expect to derive a substantial majority of our revenues relating to the Catarina gathering system 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:

- the speculative nature of drilling wells;
- a reduction in or slowing of Sanchez Energy's development program, which would directly and adversely impact demand for our gathering and processing services;
- a decline in natural gas, NGLs and oil prices, which have recently been extremely volatile and have declined rapidly;
- 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 ability to finance its operations and development activities;
- transportation capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation.

In addition, recent lower oil, natural gas and NGL prices have caused and may further cause Sanchez Energy to record ceiling limitation impairments, which would adversely affect its future business and development. Sanchez Energy utilizes the full cost method of accounting to account for its oil and natural gas exploration and development activities. Under this method of accounting, the company is required on a quarterly basis to determine whether the book value of its oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling," based upon the expected after-tax present value (discounted at 10%) of the future net cash flows from the proved reserves. Any excess of the net book value of the oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. Sanchez Energy recorded a full cost ceiling test impairment before income taxes of approximately $1,365.0 million and $213.8 million for the years ended December 31, 2015 and 2014, respectively. Based on the expectation that the current decline in average prices will continue during 2016, Sanchez Energy could incur additional non-cash impairments to its full cost pool in 2016. 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 Catarina gathering and processing agreement. We cannot predict the extent to which Sanchez Energy's business would be impacted if conditions in the energy industry were to deteriorate, nor can we estimate the impact that such conditions would have on Sanchez Energy's ability to execute its drilling and development program or perform under the Catarina gathering and processing agreement. 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 impairment to Sanchez Energy's financial condition or adverse changes in 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, material adverse changes at Sanchez Energy could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing, or could 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 adversely affect our business and operating results.

The volumes that support the Catarina gathering system depend on the level of production from wells connected to the Catarina gathering system, 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, 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 the Catarina gathering system, 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 the Catarina gathering system 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 Sanchez Energy's Catarina lease, 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. If Sanchez Energy fails to meet this minimum drilling commitment, Sanchez Energy would forfeit its acreage under the 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. Sanchez Energy could elect to reduce its drilling and completion activity if commodity prices decrease. Declines in commodity prices could have a negative impact on Sanchez Energy's development and production activity, and if sustained, could lead to a material decrease in such activity. 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 the Catarina gathering system, Sanchez Energy and other producers may choose not to develop, or be prohibited from developing, those reserves. If reductions in development activity result in our inability to maintain the current levels of throughput on the Catarina gathering system, those reductions could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

The Catarina gathering and processing agreement with Sanchez Energy contains provisions that can reduce the cash flow stability that the agreement was designed to achieve.

The Catarina gathering and processing agreement with Sanchez Energy 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 the Catarina gathering system 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 Catarina gathering and processing agreement. In addition, the Catarina gathering and processing agreement also includes a minimum quarterly quantity, which is a total amount of natural gas, NGLs and oil that Sanchez Energy must flow on the Catarina gathering system (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 Catarina gathering and processing 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.

Under certain circumstances, it is possible that the combined effect of the minimum volume commitment provisions could result in our receiving no revenues or cash flows from Sanchez Energy in a given period. In the most extreme circumstances:

- we could incur operating expenses with no 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.

We do not intend to obtain independent evaluations of natural gas, NGLs and oil reserves connected to the Catarina gathering system 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 natural gas, NGLs and oil reserves, including those of Sanchez Energy, connected to the Catarina gathering system on a regular or ongoing basis. Moreover, even if we did obtain independent evaluations of the natural gas, NGLs and oil reserves connected to the Catarina gathering system, such evaluations may prove to be incorrect. Crude oil and natural gas reserve engineering requires subjective estimates of underground accumulations of crude oil and natural gas and assumptions concerning future crude 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 the Catarina gathering system or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to the Catarina gathering system 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.

Interruptions in operations at the Catarina gathering system may adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations depend upon the infrastructure that we have developed, constructed or acquired. Any significant interruption at any of our gathering, treating or processing facilities, or in our ability to gather, treat or process natural gas, NGLs and oil, would adversely affect our operations and cash flows available for distribution to our unitholders. Operations at our 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 our 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 in the supply of resources necessary to operate the Catarina gathering system;
- damage to our 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.

The Catarina gathering system is concentrated in two counties in the Eagle Ford Shale of Texas, making us vulnerable to risks associated with operating in one major geographic area.

All of the Catarina gathering system is located in two counties 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.

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.

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 the Catarina gathering system 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 the Catarina gathering system for third-party volumes, we may not be able to compete effectively with third-party gathering 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 the Catarina gathering system is located restricts the Catarina gathering system 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 the Catarina gathering and processing agreement and the fact that a substantial portion of the capacity of the Catarina gathering system will be necessary to service Sanchez Energy's production and development and completion schedule, (ii) the current nature of the Catarina gathering system, (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.

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 renew or replace volume of throughput after the expiration of the five-year minimum volume commitment from the Catarina gathering and processing agreement sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. The Catarina gathering system competes primarily with other natural gas, NGL and oil gathering 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 gathering systems 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 gathering systems instead of using the 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.

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

The Catarina gathering system connects 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 all of the land on which the Catarina gathering system is located, which could result in disruptions to our operations.

We do not own all of the land on which the Catarina gathering system has been constructed, 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 the Catarina gathering system. 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 you.

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 the purchase agreement entered into in connection with the acquisition of midstream assets in the Western Catarina area from Sanchez Energy, subject to certain exceptions, Sanchez Energy has agreed to provide us the first right to make an offer to purchase midstream assets that it desires to transfer to any unaffiliated person through 2030. 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.

In addition, Sanchez Energy is under no obligation to accept any offer made by us. Furthermore, for a variety of reasons, we may decide not to exercise this right when it becomes available.

Risks Related to Our Exploration and Production Business

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 flow and any ability to pay distributions to our unitholders.

Drilling activities are subject to many risks, including the risk that we will 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 gas leaks, oil spills, compressor incidents, pipeline ruptures and discharges of toxic gases;
- water pollution;
- fires;
- accidents or natural disasters;
- blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids; and
- loss or theft of data due to cyber-attacks.

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 flow 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.

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.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

We have identified and scheduled drilling locations for our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our future development drilling program. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. In addition, no proved reserves are assigned to any of the potential drilling locations we have identified, and therefore, there may be greater uncertainty with respect to the likelihood of drilling and completing successful commercial wells at these potential drilling locations. Our final determination of whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations that we have identified will be drilled within our expected timeframe or will ever be drilled, or if we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse affect on our financial condition, results of operations and ability to pay distributions.

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 drill additional wells, 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 flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which could adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

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

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

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

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

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

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

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

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

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

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

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, production data factors change or drilling results deteriorate, 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 on our ability to borrow funds under our credit facility, which in turn may adversely affect our ability to make cash distributions to our unitholders.

Due to our lack of asset and geographic diversification, adverse developments in our core operating areas would affect our results of operations, reduce our operating cash flows and impact our profitability.

The majority of our oil and gas properties are located in the Mid-Continent region of the United States and is predominantly coalbed methane natural gas. We currently have a limited amount of drilling opportunities in our existing asset base that enable us to focus on oil completions. Due to our lack of diversification in asset type, commodity type and location, an adverse development in the oil and natural gas business or our geographic area would have a significantly greater impact on the price which we receive for our oil and natural gas, our results of operations, and any cash available to make any additional capital investments or to make any distributions to our unitholders than if we maintained more diverse assets and locations.

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.

We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC; Keystone Gas Corporation; Scissortail Energy, LLC; Cotton Valley Compression, L.L.C.; Cherokee Basin Pipeline, LLC and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals, L.P. and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production in the Central Kansas Uplift are marketed by the operators of the wells. Our oil and natural gas production in the onshore Texas and Louisiana Gulf Coast region 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 exploration and production activities.

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

Certain of our undeveloped leasehold acreage are subject to leases that may expire in the near future, and our concession agreement with the Osage Nation has certain terms and conditions which must be fulfilled by us.

Some of the leases that we hold are still within their original lease term and are not currently held by production. Unless we establish commercial production on the properties subject to these leases, these leases will expire. Our concession agreement with the Osage Nation also has certain terms and conditions which must be fulfilled by us. If our leases expire or our concession with the Osage Nation terminates, we will lose our right to develop the related properties, which would reduce our future operating cash flows and our cash available to pay distributions.

Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay our 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 our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues, operating cash flows and cash available to make future investments or to pay distributions.

Locations that we decide to drill may not yield oil and natural gas in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and natural gas to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have a material adverse impact on our business, financial position and results of operations.

The coalbeds from which we produce natural gas frequently contain water that may hamper our ability to produce natural gas in commercial quantities or adversely affect our profitability.

Unlike conventional natural gas production, coalbeds frequently contain water that must be removed in order for the natural gas to desorb from the coal and flow to the wellbore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce natural gas in commercial quantities. In addition, the cost of water disposal may be significant, may increase over time and may reduce our profitability.

We may face unanticipated water disposal or processing costs.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to shut in wells, reduce drilling activities or upgrade facilities for water handling or treatment. The costs to treat or dispose of this produced water may increase if any of the following occur:

- we cannot renew or obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our 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 prospects and 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 prospects and productive properties than our financial and personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent on our ability to evaluate, select and finance the acquisition of suitable properties and our ability to consummate transactions in a highly competitive environment. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties and available funds. Many of our larger competitors not only drill for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. Other companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. 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 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, local and Native American tribal 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 Wall Street Reform and Consumer Protection Act ("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, local and Native American tribal laws and regulations as interpreted and enforced by governmental and Native American tribal authorities possessing jurisdiction over various aspects of the exploration, 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 and Native American tribal authorities. For example, we have a concession agreement from the Osage Nation for a substantial portion of our leases in the Cherokee Basin. Failure or delay in obtaining regulatory approvals, leases, or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil and natural gas we may produce and sell.

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

A substantial portion of Sanchez Energy's natural gas, NGLs and oil production 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 the Catarina gathering system, 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 the Catarina gathering system 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 under the Catarina gathering and processing agreement. 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 the Catarina gathering system also poses risks of environmental liability due to leakage, migration, releases or spills from our operations 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 crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability.

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

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in HMAs. 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. In September 2013, PHMSA finalized rules consistent with the signed act that increased the maximum administrative civil penalties for violations of the pipeline safety laws and regulations that occur after January 2012 to $200,000 per violation per day, with a maximum of $2,000,000 for a related series of violations. Should our operation of the Catarina gathering system 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 to solicit comments on the need for changes to its safety regulations, including whether to extend the integrity management requirements to additional types of facilities pipelines, such as gathering pipelines and related facilities. 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 flow. 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, 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 wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

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

Risks Related to Financing and Credit Environment

Our credit facility has substantial restrictions and financial covenants and requires periodic borrowing base redeterminations.

We depend on our credit facility for future capital needs. The credit facility 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 flow 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 facility 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 facility 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 facility;
- 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 facility 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 facility 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 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 5.0 initially, 4.75 for the second full quarter after the midstream acquisition and 4.5 thereafter. 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 facility contains a condition to borrowing and a representation that no material adverse effect has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a material adverse effect were to occur, we would be prohibited from borrowing under the credit facility and we would be in default under the credit facility, which could cause all of our existing indebtedness to become immediately due and payable.

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 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.

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

Our credit facility matures on March 31, 2020. We may not be able to extend, replace or refinance our existing credit facility 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 facility upon its maturity. Any of the foregoing could materially and adversely affect our business, liquidity, cash flows and prospects.

Our credit facility may restrict us from paying any distributions on our outstanding units.

We have the ability to pay distributions to unitholders under our credit facility from available cash, including cash from borrowings under the credit facility, 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 facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses. 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 of directors of our general partner.

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.

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 facility 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 facility 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 flow 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 facility. As we have hedged a large percentage of our future expected production volumes, the cash flow 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 interests rates may also increase the borrowing costs associated with our credit facility. 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 swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder and other regulations, including EMIR, may adversely affect our ability to hedge risks associated with our business and our results of operations and cash flows.

The swaps regulatory provisions of the 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 setting 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 crude 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 swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder, we could 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 margin with respect to uncleared swaps from their counterparties other than non-financial end users of swaps. The requirements of those rules are to be phased in over an extended period to commence on September 1, 2016. Were we not to qualify as a non-financial end user as to any of our uncleared swaps and have to post margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would be increased. 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 require us to post 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.

Provisions of the Dodd-Frank Act have caused or may cause certain of our historical derivatives counterparties to spin off some or all of their derivatives activities into separate entities. Those entities could be our counterparties in future swaps and may not be as creditworthy as our historical counterparties.

The European Market Infrastructure Regulation ("EMIR") includes regulations related to the trading, reporting and clearing of 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 that we enter 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 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 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, and increase our exposure to less creditworthy counterparties. 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 otherwise 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.

A principal focus of our strategy is to increase the quarterly cash distributions that we pay to our unitholders over time. 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 facility 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 generally described in this caption "Risk Factors". These and other factors that affect that amount that we can distribute include:

- the amount of oil and natural gas that we produce;
- the amount of revenue generated from the Catarina gathering system;

- 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 facility as determined by our lenders;
- the amount of our indebtedness outstanding;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon;
- the amount of working capital required to operate our business and our ability to make working capital borrowings under our credit facility;
- fluctuations in our working capital needs;
- the amount of cash reserves established by the board of directors of our general 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 future cash flow from operations 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 facility, 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. Our available cash excludes any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses. We are subject to additional future borrowing base redeterminations before our credit facility 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 cash flow and not our profitability.

The amount of cash that we have available for distribution depends primarily on our cash flow, 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 drilling opportunities, our financial condition and our profitability.

Our revenue, profitability and cash flow 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 cash flow. In particular, declines in commodity prices will reduce the value of our reserves, our cash flow, our ability to borrow money or raise capital and our ability to pay distributions. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and level of foreign imports of oil and natural gas;
- the level of consumer product demand; weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including those in West Africa, the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries 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 cash flow 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 substantial capital expenditures, which will reduce any cash available for distribution to our unitholders.

We will need to make substantial capital expenditures to maintain our reserves over the long-term. These maintenance capital expenditures may include capital expenditures associated with drilling and completion of additional wells to offset the production decline from our producing properties or additions to our inventory of unproved properties or our proved reserves to the extent such additions maintain our asset base. These expenditures could increase as a result of:

- changes in our reserves;
- changes in oil and natural gas prices;
- changes in labor and drilling costs;
- our ability to acquire, locate and produce reserves;
- changes in leasehold acquisition or concession costs; and
- government regulations relating to safety, taxation and the environment.

Our maintenance 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. If we fail to make sufficient capital expenditures, our future production levels will decline, which may materially and adversely affect our future revenues and amount of cash available for distribution to our unitholders.

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 of directors of our general partner 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 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 flow 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 facility, 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 flow 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 that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the risk of title defects discovered after closing;
- inaccurate assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to transition and integrate successfully or timely the businesses we acquire;
- the cost of transition and integration of data systems and processes;
- potential environmental problems and costs;
- the assumptions of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management’s attention from other business concerns;
- increased demands on existing personnel and on our organizational structure;
- disputes arising out of acquisitions;
- customer or key employee losses of the acquired businesses; and
- the failure to realize expected growth or profitability.

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

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 Managers 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.

- 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 the 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 of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

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 his U.S. federal income tax status or nationality, citizenship or related status. If a limited partner fails to furnish information about his 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 his units and may not receive distributions in kind upon our liquidation.

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

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

- the 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 of the board of directors of our general partner; 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 holders of our common units 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 of directors of our general partner 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 of directors of our general partner and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, and under our partnership agreement, a determination, other action or failure to act by our general partner and any committee thereof (including the conflicts committee) will be deemed to be in good faith unless the general partner, the board of directors of the general partner 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 of directors of our general partner relating to the conflict transactions described below, the board of directors of our general partner did not believe that the specified standards were met, and, except as specifically provided by our partnership agreement, neither our general partner, the board of directors of our general partner 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 of directors of our general partner, 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 of directors of our general partner 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 of directors of our general partner 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 of directors of our general partner 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 of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

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

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

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue 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 its board of directors. Rather, the board of directors of our general partner 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 the 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 the 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 of directors of our general partner, 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 the 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 board of directors and officers of our general partner with their own choices and to control the decisions taken by the board of directors and officers.

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

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

We will be able 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 the 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 the common units may decline.

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

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

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

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

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

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

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

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

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

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

The NYSE MKT 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 MKT does not require us to have a majority of independent directors on our general partner's board of directors 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 MKT corporate governance requirements.

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 that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the risk of title defects discovered after closing;
- inaccurate assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to transition and integrate successfully or timely the businesses we acquire;

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

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

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. A publicly traded partnership such as us may be treated as a corporation for U.S. federal income tax purposes unless it satisfies 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. Failing 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 rates, which is currently at a maximum marginal rate of 35%, and would likely pay state and local income tax at varying rates. Distributions to unitholders would generally be taxed as corporate distributions, and no income, gains, losses, deductions or credits 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.

In addition, recently enacted legislation applicable to partnership tax years beginning after 2017 changes the audit procedures for large partnerships and in certain circumstances would permit the IRS to assess and collect taxes (including any applicable penalties and interest) resulting from partnership-level U.S. federal income tax audits directly from us in the year in which the audit is completed. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

At the state level, changes in current state law may subject us to additional entity-level taxation by individual states. Due to widespread state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may materially reduce the cash available for distribution to our unitholders.

Therefore, 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 federal, state or local income tax purposes, the minimum quarterly distribution and the target distributions may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, the Department of the Treasury and IRS have issued proposed regulations that, if finalized in their current form, would restrict the types of natural resource activities that generate qualifying income for publicly traded partnerships. We believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the proposed regulations. However, the proposed regulations could be changed before they are finalized and could take a position that is contrary to our interpretation of Section 7704 of the Internal Revenue Code of 1986, as amended. In addition, from time to time the Obama Administration and members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal income tax laws that would adversely affect publicly traded partnerships. 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 to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could adversely affect an investment in our common units.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Other proposed changes could affect our ability to remain taxable as a partnership for U.S. federal income tax purposes. The passage of any legislation with similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and 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 that results from that income.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for U.S. federal income tax purposes.

We will be considered to have technically terminated our existing partnership and having formed a new partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year of termination. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead we would be treated as a new partnership for U.S. federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred. Pursuant to an IRS relief procedure the IRS may allow, among other things, a constructively terminated partnership to provide a single Schedule K-1 for the calendar year in which a termination occurs.

A successful IRS contest of the U.S. federal income tax positions we take may adversely affect the market for our common units, and the costs of any contest will reduce cash available for distribution.

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. Moreover, recently enacted legislation applicable to partnership tax years beginning after 2017 changes the audit procedures for large partnerships and in certain circumstances would permit the IRS to assess and collect taxes (including any applicable penalties and interest) resulting from partnership-level U.S. federal income tax audits directly from us in the year in which the audit is completed. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. 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.

Tax-exempt entities and foreign persons 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), and non-U.S. persons 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 may be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

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 the 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. It 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.

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 the 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 it 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 of depreciation deductions and certain other items. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

Unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to U.S. federal income taxes, our unitholders are likely 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.

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 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 the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of the 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 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 the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. The Department of the Treasury and the IRS recently adopted final Treasury regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted. Certain publicly traded partnerships, including us, may but are not required to apply the conventions provided by the Treasury regulations. If the IRS were to challenge our proration method, our items of income, gain, loss and deduction could be reallocated among our unitholders.

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 those common units. If so, he 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, he 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 he may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

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

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any other material legal proceedings other than those that have been previously disclosed. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under various environmental protection statutes or other regulations to which we are subject.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common units are listed on the NYSE MKT under the symbol "SPP." On March 28, 2016, the market price for our common units was $11.58 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $30 million. The following table presents the high and low closing price for our common units during the periods indicated.

	Common Stock	
	High	Low
2015		
First Quarter (1)	$ 20.00	$ 12.40
Second Quarter (1)	$ 22.90	$ 17.10
Third Quarter (1)	$ 19.20	$ 4.10
Fourth Quarter	$ 15.49	$ 8.69
2014		
First Quarter (1)	$ 28.50	$ 21.70
Second Quarter (1)	$ 27.40	$ 23.00
Third Quarter (1)	$ 42.30	$ 26.30
Fourth Quarter (1)	$ 37.10	$ 12.20

(1) All closing prices before August 4, 2015 have been adjusted for the 1:10 stock split.

Holders

The number of unitholders of record of our common units was approximately 68 as of March 28, 2016. The number of registered holders does not include holders that have common units held for them in "street name," meaning that the common units are held for their accounts by a broker or other nominee. In these instances, the brokers or other nominees are included in the number of registered holders, but the underlying unitholders that have units held in "street name" are not.

Distributions

From the second quarter of 2009 through the second quarter of 2015, we did not pay distributions on our common units. On November 30, 2015, we paid a distribution with respect to the quarter ended September 30, 2015 in the amount of $0.400 per common unit. On February 9, 2016, we announced that the board of directors of our general partner approved a cash distribution of $0.406 per common unit for the fourth quarter of 2015. The distribution was paid on February 29, 2016 to unitholders of record on February 19, 2016.

Cash Distribution Policy

Within 60 days after the end of each quarter, it is our intent to distribute to holders of common units on a quarterly basis the minimum quarterly distribution of $0.50 per unit (or $2.00 on an annualized basis) to the extent that we have sufficient cash after the establishment of cash reserves and the payment of our expenses, including payments to our general partner and its affiliates.

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 at our minimum quarterly distribution rate or at any other rate. Our cash distribution policy is subject to certain restrictions and may be changed at any time. The reasons for such uncertainties in our stated cash distribution policy include the following factors:

- Our ability to make cash distributions may be limited by certain covenants in our revolving credit facility, including a requirement that no event of default exists and a restriction that the borrowings outstanding, net of available cash, under our credit facility cannot exceed 90% of the borrowing base, after giving effect to the proposed distribution. Should we be unable to satisfy these covenants, we will be unable to make cash distributions notwithstanding our cash distribution policy.

- Our general partner will have the authority to establish cash reserves for the prudent conduct of our business, including 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 that we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish. Any decision to establish cash reserves made by our general partner in good faith will be binding on our unitholders.

- Prior to making any distribution on the 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. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses may include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. We currently estimate that the aggregate amount of fees and reimbursed expenses pursuant to the Services Agreement will be $5.8 million annually. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce our ability to pay distributions to our unitholders.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions that we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner.

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

- We may lack sufficient cash to pay distributions to our unitholders due to 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 and 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 making any distributions from capital surplus.

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

General Partner Interest

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

Incentive Distribution Rights

All of the incentive distribution rights are held by Manager. Incentive distribution rights represent the right to receive increasing percentages (15%, 13%, 23% and 35.5%) of quarterly distributions from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved.

For any quarter in which we have distributed cash from operating surplus to the 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%

Securities Authorized for Issuance Under Equity Compensation Plans

See “Item 12. Security Ownership of Certain Benefits Owners” for information regarding our equity compensation plan as of December 31, 2015.

Unregistered Sales of Securities

During the three months ended December 31, 2015, in connection with the quarterly distribution for the Class A Preferred Units, we issued the following additional Class A preferred units ("PIK Class A Units") to the holders of the Class A Preferred Units (in thousands, except unit amounts):

Period	PIK Class A Units	Implied Fair Value	Date of Distribution
October 1, 2015 - October 31, 2015	—	—	—
November 1, 2015 - November 30, 2015[1]	278,276	$ 445,242	November 30, 2015
December 1, 2015 - December 31, 2015	—	—	—

(1) Distribution was made with respect to the three months ended September 30, 2015. The board of directors of our general partner authorized the issuance of 285,233 PIK Class A Units in February 2016 with respect to the three months ended December 31, 2015.

No proceeds were received as consideration for the issuance of the PIK Class A Units. The PIK Class A Units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended. For additional information regarding the Class A Preferred Units, see Note 14. "Members' Equity/Partners' Capital" of our Notes to Consolidated Financial Statements.

Issuer Purchases of Equity Securities

The following table provides information relating to our purchase of our common units in the fourth quarter of 2015.

Period	Total Number of Common Units Purchased	Average Price Paid
October 1, 2015 - October 31, 2015	—	—
November 1, 2015 - November 30, 2015	32,600	$12.16
December 1, 2015 - December 31, 2015	110,585	$14.11
Total	143,185	$13.67

(1) On November 10, 2015, the board of directors of our general partner approved a $10 million common unit repurchase plan (the "Unit Repurchase Plan"). Under the new Unit Repurchase Plan, we may repurchase up to $10 million of our common units. We may repurchase our common units from time to time, in amounts and at prices that we deem appropriate, subject to market conditions and other considerations. Our repurchase may be executed using open market purchases, privately negotiated agreements or other transactions. The repurchases will be funded from cash on hand or available borrowings. The Unit Repurchase Plan may be suspended or discontinued at any time without prior notice.

Default Upon Senior Securities

There were no defaults on senior securities for the years ended December 31, 2015 or December 31, 2014.

Item 6. Selected Financial Data

As a smaller reporting company, we are not required to provide the information required by this item.

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

The following discussion and analysis should be read in conjunction with accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read "Cautionary Statement Regarding Forward-Looking Statements." Also, please read the risk factors and other cautionary statements described under the heading "Item 1A--Risk Factors" included elsewhere in this Annual Report.

Overview

We were formed in 2005 as a Delaware limited liability company until our conversion on March 6, 2015 into a Delaware limited partnership. We are focused on the acquisition, development, ownership and operation of midstream and other energy producing assets. Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale (the "Catarina gathering system") from Sanchez Energy and entered into a 15-year gathering and processing agreement with Sanchez Energy (the "Catarina gathering and processing agreement"). We have also commenced a process to sell oil and gas properties in the Mid-Continent region.

Our primary business objective is to create long-term value and to generate stable cash flows that allow us to make and grow distributions over time. We plan to achieve our objective by executing our business strategy, which is to:

- Conduct a sales process to evaluate and pursue the possible divestiture of our Mid-Continent assets in 2016;
- Align our asset base, interests and operations with our sponsor, SOG;
- Grow our business by acquiring cash producing assets involved in production, gathering and processing activities with minimal maintenance capital requirements and low overhead; and
- Reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs.

Significant Operational Factors in 2015

Some key highlights of our business activities for the year ended December 31, 2015 were:

- In March 2015, we converted our organizational structure from a limited liability company to a limited partnership.
- In March 2015, we purchased escalating working interests in 59 wellbores in the Palmetto Field in Gonzales, Texas from Sanchez Energy for $85 million.
- In March and April 2015, we issued 10,859,375 Class A Preferred Units for gross proceeds to us of $17,375,000, with the proceeds being used for the Palmetto acquisition.
- In March 2015, we amended and restated our credit facility to, among other matters, extend the maturity date to March 2020 and increase the maximum commitment to $500 million.

- In April 2015, we entered into an at-the-market sales agreement with MLV & Co. LLC to sell from time to time up to $100 million of common units.
- In August 2015, we effectuated a 1-for-10 reverse split of our common units.
- In October 2015, we consummated the acquisition of the Catarina gathering system from Sanchez Energy for $345.8 million, and we entered into the Catarina gathering and processing agreement with Sanchez Energy.
- In October 2015, we issued 19,444,445 of Class B Preferred Units for gross proceeds to us of $350 million, with the proceeds being used for the Catarina gathering system acquisition.
- In October 2015, we amended our credit facility to, among other matters, establish a $200 million borrowing base for our oil and natural gas properties and our midstream assets.
- In November 2015, the board of directors of our general partner approved a $10 million common unit repurchase plan.

How We Evaluate Our Operations

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

- our Adjusted EBITDA
- our operating expenses; and
- our throughput volumes on the gathering system upon acquiring those assets.

Throughput Volumes

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

Operating Expenses

Our management seeks to maximize the Adjusted EBITDA in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (which lease operating expenses, labor, vehicle, 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 gas production or the throughput volumes on the gathering system but fluctuate depending on the scale of our operations during a specific period.

Non-GAAP Financial Measures—Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) adjusted by:

- interest (income) expense, net which includes:
  - interest expense;

  - interest expense net (gain) loss on interest rate derivative contracts; and
  - interest (income)
- income tax expense (benefit);
- depreciation, depletion and amortization;
- asset impairments and exploration costs;
- accretion expense;
- (gain) loss on sale of assets;
- (gain) loss from equity investment;
- unit-based compensation programs;
- unit-based asset management fees;
- (gain) loss on mark-to-market activities; and
- (gain) loss on embedded derivatives.

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 flow 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:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- 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 generally accepted accounting principle ("GAAP") measures most directly comparable to Adjusted EBITDA are net income and net cash provided by operating activities. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income and net cash provided by operating activities. Adjusted EBITDA should 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.

The following table presents a reconciliation of net income (loss) to Adjusted EBITDA, our most directly comparable U.S. GAAP performance measure, for each of the periods presented (in thousands):

	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
Net income (loss)	$ (137,056)	$ 9,503
Adjusted by:		
Interest expense, net	4,207	2,076
Income tax expense	55	—
Depreciation, depletion and amortization	14,536	17,533
Asset impairments and exploration costs	125,726	5,424
Accretion expense	1,099	604
(Gain) loss on sale of assets	(111)	223
Unit-based compensation programs	2,454	1,298
Unit-based asset management fees	937	—
(Gain) loss on mark-to-market activities	(4,780)	(12,228)
Loss on embedded derivatives	9,982	—
Adjusted EBITDA	$ 17,049	$ 24,433

Results of Operations by Segment

Exploration & Production Operating Results

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

	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	Variance	
Revenues:				
Natural gas sales at market price	$ 12,128	$ 25,481	$ (13,353)	(52)%
Natural gas hedge settlements	7,178	7,695	(517)	(7)%
Natural gas mark-to-market activities	(1,175)	(1,824)	649	35.58 %
Natural gas total	18,131	31,352	(13,221)	(42)%
Oil sales	16,151	26,353	(10,202)	(39)%
Oil hedge settlements	13,191	(69)	13,260	NM [b]
Oil mark-to-market activities	5,955	14,053	(8,098)	(58)%
Oil total	35,297	40,337	(5,040)	(12)%
Natural gas liquid sales	1,597	2,477	(880)	(36)%
Miscellaneous income	1,678	3,106	(1,428)	(46)%
Total revenues	56,703	77,272	(20,569)	(27)%
Operating expenses:				
Lease operating expenses	19,890	21,012	(1,122)	(5)%
Cost of sales	595	1,487	(892)	(60)%
Production taxes	1,792	3,200	(1,408)	(44)%
General and administrative	26,109	16,499	9,610	58 %
Exploration costs	1,866	—	1,866	NM [b]
Gain on sale of assets	(111)	223	(334)	NM [b]
Depreciation, depletion and amortization	10,330	17,533	(7,203)	(41)%
Asset impairments	123,860	5,424	118,436	NM [b]
Accretion expenses	1,048	604	444	74 %
Total operating expenses	185,379	65,982	119,397	NM [b]
Other expenses (income):				
Interest expense	4,207	2,076	2,131	NM [b]
Loss on embedded derivatives	—	—	—	NM [b]
Other income	(670)	(289)	(381)	NM [b]
Total other expenses	3,537	1,787	1,750	NM [b]
Total expenses	188,916	67,769	121,147	NM [b]
Income (loss) before income taxes	$ (132,213)	$ 9,503	$ (141,716)	NM [b]
Net production:				
Natural gas production (Mcf)	5,986	6,911	(925)	(13)%
Oil production (MBbl)	331	286	45	16 %
Natural gas liquids production (MBbl)	100	71	29	41 %
Total production (MBOE)	1,428	1,509	(81)	(5)%
Average daily production (BOE/d)	3,913	4,134	(221)	(5)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.23	$ 4.80	$ (1.57)	(33)%
Natural gas price per Mcf without hedge settlements	$ 2.03	$ 3.69	$ (1.66)	(45)%
Oil price per Bbl with hedge settlements	$ 88.65	$ 91.90	$ (3.25)	(4)%
Oil price per Bbl without hedge settlements	$ 48.79	$ 92.14	$ (43.35)	(47)%
Liquid price per Bbl without hedge settlements	$ 16.03	$ 34.89	$ (18.86)	(54)%
Total price per BOE with hedge settlements	$ 35.18	$ 41.05	$ (5.87)	(14)%
Total price per BOE without hedge settlements	$ 20.92	$ 36.00	$ (15.08)	(42)%
Average unit costs per BOE:				
Field operating expenses [a]	$ 15.18	$ 16.05	$ (0.87)	(5)%
Lease operating expenses	$ 13.93	$ 13.93	$ (0.00)	(0)%
Production taxes	$ 1.25	$ 2.12	$ (0.87)	(41)%
General and administrative expenses	$ 18.28	$ 10.93	$ 7.35	67 %
General and administrative expenses without unit-based compensation	$ 16.56	$ 10.07	$ 6.49	64 %
Depreciation, depletion and amortization	$ 7.23	$ 11.62	$ (4.39)	(38)%

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes
(b) Variances deemed to be Not Meaningful "NM".

Production. For the year ended December 31, 2015, 23% of our production was oil, 7% was NGLs and 70% was natural gas as compared to the year ended December 31, 2014, where 19% of our production was oil, 6% was NGLs and 75% was natural gas. The amount of oil as a percentage of total production has increased during the year December 31, 2015 due to the addition of production from the Eagle Ford properties acquired on March 31, 2015, which are significantly more weighted towards oil than our previous asset base. Assuming no further acquisitions, we expect this product mix to remain relatively consistent for 2016.

Oil, natural gas and natural gas liquids sales. Unhedged oil sales decreased $10.2 million, or 39%, to $16.2 million for the year ended December 31, 2015, compared to $26.4 million for the same period in 2014. NGL sales decreased $0.9 million, or 36%, to $1.6 million for the year ended December 31, 2015, compared to $2.5 million for the same period in 2014. Unhedged natural gas sales decreased approximately $13.4 million, or 52%, to $12.1 million for the year ended December 31, 2015, compared to $25.5 million for the same period in 2014.

Including hedges and mark-to-market activities, our total production related revenue decreased $20.6 million for the year ended December 31, 2015, compared to the same period in 2014. This decrease was the result of a $26.2 million decrease attributable to lower market prices for all products and losses on mark-to-market activities of $7.4 million, offset by a $1.7 million increase related to higher sales volumes and a $12.7 million increase in settlements on our commodity derivatives. The remainder of the decrease is related to a decrease between the periods of $1.4 million in miscellaneous income.

The following tables provide an analysis of the impacts of changes in average realized production volumes and prices between the periods on our unhedged revenues from the year ended December 31, 2014 to the year ended December 31, 2015 (dollars in thousands):

	2015 Average Sales Price[a]	2014 Average Sales Price[a]	Average Sales Price Difference	2015 Volume	Revenue Decrease due to Price[a]
Natural gas (Mcf)	$ 2.03	$ 3.69	$ (1.66)	5,986	$ (9,943)
Oil (MBbl)	$ 48.79	$ 92.14	$ (43.35)	331	$ (14,348)
Natural gas liquids (Mbl)	$ 16.03	$ 34.89	$ (18.86)	100	$ (1,878)
Total oil equivalent (Mboe)	$ 20.92	$ 36.00	$ (15.08)	1,428	$ (26,169)

(a) Average sales prices presented represent on a per BOE basis.

	2015 Production Volume	2014 Production Volume	Production Volume Difference	2014 Average Sales Price[a]	Revenue Increase/(Decrease) due to Production
Natural gas (Mcf)	5,986	6,911	(925)	$ 3.69	$ (3,410)
Oil (MBbl)	331	286	45	$ 92.14	$ 4,146
Natural gas liquids (Mbl)	100	71	29	$ 34.89	$ 998
Total oil equivalent (Mboe)	1,428	1,509	(81)	$ 36.00	$ 1,734

(a) Average sales prices presented represent on a per BOE basis.

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, 2015 by $3.0 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 gas revenues. For the year ended December 31, 2015, the non-cash mark-to-market gains were $4.7 million, compared to a gain of $12.2 million for the same period in 2014. Cash settlements, including settlements receivable, for our commodity derivatives were $20.4 million for the year ended December 31, 2015, compared to $7.6 million for the year ended December 31, 2014.

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

Lease operating expenses decreased $1.1 million, or 5%, to $19.9 million for the year December 31, 2015, compared to $21.0 million for the same period in 2014. On a per unit basis, lease operating expenses were $13.93 per BOE, for the years ended December 31, 2015 and 2014. This decrease in operating expenses resulted from a proportional decrease in total production, leaving lease operating expenses per BOE flat for the comparative periods.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses increased $9.6 million, or 58%, to $26.1 million for the year December 31, 2015, compared to $16.5 million for the same period in 2014. Our general and administrative expenses were higher in 2015 due to a $2.5 million increase in labor and incentive compensation costs relating to severance costs associated with the departure of our former Chief Executive Officer, a $3.0 million increase in salaries and wages, a $1.1 million increase in unit-based compensation, $1.4 million increase in fees incurred for acquisitions, and a $1.6 million increase in management fee expenses.

Our general and administrative expenses were $18.28 per BOE for the year ended December 31, 2015, compared to $10.93 per BOE for the same period in 2014. Excluding unit-based compensation, our general and administrative costs were $16.56 per BOE for the year ended December 31, 2015, compared to $10.07 per Boe for the same period in 2014.

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

Our depreciation, depletion and amortization expense for the year ended December 31, 2015 was $10.3 million, or $7.23 per BOE, compared to $17.5 million, or $11.62 per BOE, for the same period in 2014. This overall decrease is the result of lower property values due to non-cash impairment charges previously recorded as well as increases to total proved reserves between the periods impacting the depletion rate. Our non-oil and gas properties are depreciated using the straight-line basis. Our non-cash impairment charges for the year ended December 31, 2015 totaled $123.8 million for the Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties. During the same period in 2014, our non-cash impairment charges were approximately $5.4 million to impair the value of our oil and natural gas fields in Texas and Louisiana. The impairment expense recorded during the year ended December 31, 2015 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.

Interest expense. Interest expense for the year ended December 31, 2015 increased $2.1 million, or 103%, to $4.2 million, compared to $2.0 million for the same period in 2014. This increase was due in part to expensing of debt issuance costs which resulted from the modification of our Credit Agreement in March 2015, and the removal of one of the banks from our lending syndicate. The remainder of the increase is the result of increased borrowings under our Credit Agreement to finance a portion of the Eagle Ford acquisition on March 31, 2015.

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, except net production and average sales and costs):

	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	Variance	
Revenues:				
Gathering and transportation sales	$ 11,725	$ —	$ 11,725	NM [(a)]
Total gathering and transportation sales	11,725	—	11,725	NM [(a)]
Operating expenses:				
Lease operating expenses	98	—	98	NM [(a)]
Gathering and transportation operating expenses	2,176	—	2,176	NM [(a)]
General and administrative	—	—	—	NM [(a)]
Depreciation, amortization and accretion expense	4,206	—	4,206	NM [(a)]
Asset impairments	—	—	—	NM [(a)]
Accretion expenses	51	—	51	NM [(a)]
Total operating expenses	6,531	—	6,531	NM [(a)]
Other expenses (income):				
Interest expense	—	—	—	NM [(a)]
Loss on embedded derivatives	9,982	—	9,982	NM [(a)]
Other income	—	—	—	NM [(a)]
Total other expenses	9,982	—	9,982	NM [(a)]
Total expenses	16,513	—	16,513	NM [(a)]
Income (loss) before income taxes	$ (4,788)	$ —	$ (4,788)	NM [(a)]

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

Items Affecting the Comparability of Our Financial Results. Historical results of operations for the periods presented for the Midstream segment deemed to be not meaningful as this segment was acquired and placed into service in October 2015. As a result, year over year variances are not applicable as any revenues or expenses generated from the gathering and transportation of hydrocarbons relate exclusively to the current year. See Note 3. “Acquisitions” for additional information relating to the Western Catarina Midstream acquisition.

Gathering and transportation sales. We consummated the acquisition of the Catarina gathering system from Sanchez Energy, and we entered into the Catarina gathering and processing agreement with Sanchez Energy, in October 2015. During the fiscal year ended December 31, 2015, Sanchez Energy transported average daily production through the gathering system of approximately 4,272 Bbls of crude oil and 9,221 Boe of natural gas.

Depreciation, amortization and accretion 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 12 to 15 years for equipment, and up to 36 years for gathering facilities.

Operating expenses. Our operating expenses generally consist of gathering and transportation operating expenses, labor, vehicles, supervision, minor maintenance, tools, supplies, and integrity management expenses.

Embedded derivatives. In October 2015, we entered into a purchase agreement with Stonepeak Catarina Holdings, LLC pursuant to which we sold, and Stonepeak purchased, 19,444,445 of our newly created Class B preferred units, which are redeemable for common units beginning January 1, 2018. The purchase agreement contained provisions that must be bifurcated from the contract and valued as an embedded derivative. At the year ended December 31, 2015, we recognized a $10 million loss, as we are required to measure the embedded derivative by recognizing changes in the fair value immediately as they occur in accordance with ASC 480-10-S99.

Liquidity and Capital Resources

As of December 31, 2015, we had approximately $6.6 million in cash and cash equivalents, $0.6 million in restricted cash, and $93.0 million available under the $200 million borrowing base of our Credit Agreement in effect on such date.

Our capital expenditures during the year ended December 31, 2015 were funded with cash on hand, borrowings under our credit facility, private placements of Class A preferred units and Class B preferred units, and the issuance of common units as part of our consideration given in the Eagle Ford acquisition. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our credit facility and proceeds from the issuance of additional limited partner units. We expect that the combination of these capital resources will be adequate to meet our short-term working capital requirements, long-term capital expenditures program and expected quarterly cash distributions.

We intend to distribute at least the quarterly distribution of $0.50 per unit ($2.00 per unit on an annualized basis) on all of our common units to the extent that we have sufficient cash after the establishment of cash reserves and the payment of our expenses. 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 facility 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.

As previously disclosed, we have commenced a process to possibly sell our oil and gas properties in Oklahoma and Kansas. As a result of this proposed sale, we anticipate minimal drilling activities in the Mid-Continent region during 2016, which will reduce our capital expenditures for 2016 and result in a continued decline of our production during 2016.

Credit Facility

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto. The credit facility provides a maximum commitment of $500,000,000 and has a maturity date of March 31, 2020. Borrowings under the credit facility 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 facility is limited to the borrowing base for our oil and natural gas properties and our midstream assets. Borrowings under the credit facility are available for direct investment in oil and gas properties, acquisitions, and working capital and general business purposes. The credit facility has a sub-limit of $15,000,000 which may be used for the issuance of letters of credit. The initial borrowing base under the credit facility was $200,000,000. The borrowing base for the credit available for the upstream oil and gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is equal to the rolling four quarter EBITDA of our midstream operations multiplied by 5.0 initially, 4.75 for the second full quarter after the acquisition of the Catarina gathering system and 4.5 thereafter. 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.

At our election, interest for borrowings under the credit facility are determined by reference to (i) the London interbank rate ("LIBOR") plus an applicable margin between 1.75% and 2.75% per annum based on utilization or (ii) a domestic bank rate ("ABR") plus an applicable margin between 0.75% and 1.75% per annum based on utilization plus (iii) a commitment fee between 0.375% and 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 facility 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 facility 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 facility Agreement and exercise other rights and remedies.

The credit facility 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 facility, 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 facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At December 31, 2015, we were in compliance with the financial covenants contained in the credit facility. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our credit facility 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 facility, 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, 2015, the borrowing base under our Amended Credit Agreement was set at $200 million and we had $107 million of debt outstanding under the facility, leaving us with $93 million in unused borrowing capacity. Our Credit Agreement matures on March 31, 2020.

In May 2015, we executed an at-the-market facility that allows us to sell up to $18.6 million of common units, with any proceeds from such sales to be used for general limited partnership purposes. As of December 31, 2015, we had sold 28,700 common units (2,870 common units after adjusting for reverse unit split) for total net proceeds of less than $0.1 million. During 2015 we paid de minimis commissions to the sales agent in connection with the at-the-market facility.

In October 2015, we issued 19,444,445 of Class B Preferred Units for gross proceeds to us of $350 million, with the proceeds being used for the Catarina gathering system acquisition.

Commitments and Contractual Obligations

As of December 31, 2015, our contractual obligations included our long-term debt, in the form of a credit facility, and asset retirement obligations ("ARO"). The following table summarizes our contractual obligations as of December 31, 2015 (in thousands):

	Less than 1 Year	1-3 Years	3-5 Years	More than 5 years	Total
Long-Term Debt	$ —	$ —	$ —	$ 107,000	$ 107,000
ARO[(a)]	—	—	—	20,364	20,364
Total	$ —	$ —	$ —	$ 127,364	$ 127,364

(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 9, "Asset Retirement Obligations."

Open Commodity Hedge Positions

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

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. All of our derivatives are currently collateralized by the assets securing our credit facility 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, 2015, summarize, for the periods indicated, our hedges currently in place through December 31, 2019. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps—NYMEX (Henry Hub)

	For the Year Ended December 31, 2015 (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
2016	1,098,689	$ 4.13	1,048,146	$ 4.14	998,394	$ 4.14	963,327	$ 4.14	4,108,556	$ 4.14
2017	80,563	$ 3.52	75,829	$ 3.52	71,672	$ 3.52	67,984	$ 3.52	296,048	$ 3.52
2018	79,042	$ 3.58	75,404	$ 3.58	72,115	$ 3.58	69,122	$ 3.58	295,683	$ 3.58
2019	73,432	$ 3.62	70,648	$ 3.62	68,088	$ 3.62	65,720	$ 3.62	277,888	$ 3.62
									4,978,175	

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

	For the Year Ended December 31, 2015 (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
2016	121,005	$ 73.53	113,226	$ 73.77	106,483	$ 73.95	100,525	$ 74.10	441,239	$ 73.82
2017	57,953	$ 64.80	54,554	$ 64.80	51,570	$ 64.80	48,926	$ 64.80	213,003	$ 64.80
2018	56,798	$ 65.40	54,197	$ 65.40	51,851	$ 65.40	49,709	$ 65.40	212,555	$ 65.40
2019	52,760	$ 65.65	50,784	$ 65.65	48,960	$ 65.65	47,264	$ 65.65	199,768	$ 65.65
									1,066,565	

Cash Flow from Operations

Our net cash flow provided by operating activities for the year ended December 31, 2015, was $15.4 million, compared to net cash flow provided by operating activities of $17.0 million for the same period in 2014. This decrease was primarily related to lower average commodity prices between the periods offset by increases in cash received from our newly acquired Midstream segment.

Our cash flow from operations is subject to many variables, the most significant of which are the 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 cash flow from operations will depend on our ability to maintain and increase production through our development program or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program.

Investing Activities

Our net cash flows used in investing activities for the year ended December 31, 2015 were $428.7 million, which was primarily related to $81.4 million for cash consideration paid in the Eagle Ford acquisition, $345.8 million for cash consideration paid for the Catarina gathering acquisition, as well as $2.0 million in development expenditures focused on oil completion, offset by $0.5 million in proceeds from the sale of assets during the period. We had no net well and net recompletion in progress at December 31, 2015.

During the year ended December 31, 2014, our cash capital expenditures were $6.4 million, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $3.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.7 million in development expenditures focused on properties in Texas and Louisiana. We completed eight net wells and six net recompletions during the year ended December 31, 2014.

Financing Activities

Our cash flows provided by financing activities were $415.6 million for the year ended December 31, 2015, compared to $11.2 million used in financing activities for the same period in 2014. During the year ended December 31, 2015, we had borrowings under our Credit Agreement of $107.0 million, $42.5 million of which was paid to satisfy amounts due under the Second Amended and Restated Credit Agreement, which was refinanced on March 31, 2015. We received $17.4 million from the private placement of Class A Preferred Units during the period, while incurring $0.8 million in offering expenses. We also incurred $1.3 and $0.6 million in debt issuance costs associated with the modification of our Credit Agreement on March 31, 2015 and October 14, 2015 respectively. We used $0.6 million to fund the cost of units tendered by employees for tax withholdings related to the vesting of units during the period and spent $2.2 million to retire common units. Further, we received $350 million for the issuance of Class B Preferred Units in connection with the Catarina gathering system acquisition.

Our net cash used by financing activities was $11.2 million for the year ended December 31, 2014. We had borrowings under our Credit Agreement of $5.8 million for working capital purposes and repayments of $14.0 million. We used $1.65 million to purchase the Class C and Class D interests from the owner thereof to settle litigation. We used $0.8 million for the payment of another litigation settlement of $6.5 million, which had been accrued at December 30, 2013, but was not paid until the second quarter of 2014. We used $0.4 million the year ended December 31, 2014 to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

Off-Balance Sheet Arrangements

As of December 31, 2015, 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. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through December 31, 2015, we have not suffered any significant losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group Limited, purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $2.0 million in purchases through January 31, 2016. As of December 31, 2015, we had no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Kinder Morgan Energy Partners, L.P., purchases a portion of our natural gas production in Oklahoma and Kansas. As of December 31, 2015, we had no past due receivables from Scissortail.

Derivative Counterparties

As of December 31, 2015, our derivatives were with ING, SunTrust Bank, and Royal Bank of Canada, all of whom are lenders in our credit facility. All of our derivatives are currently collateralized by the assets securing our credit facility and therefore currently do not require the posting of cash collateral. As of December 31, 2015, each of these financial institutions had an investment grade credit rating.

Credit Facility

As of December 31, 2015, the banks and their percentage commitments in our credit facility were: Royal Bank of Canada (14%), Compass Bank (12.5%), SunTrust Bank (12.5%), Capital One, N.A. (12.5%), Comerica Bank (12.5%), OneWest Bank, N.A. (9%), Citbank, N.A. (9%), Credit Suisse AG, Caymen Islands (9%) and ING Capital (9%). As of December 31, 2015, each of these financial institutions had an investment grade credit rating.

Outlook

During 2015, our business objectives were to acquire long-lived assets that deliver stable cash flows and return to making a distribution to unitholders. We believe that our relationships with SOG and Sanchez Energy and their affiliates were critical to our success in meeting those objectives.

Our primary goal during the next 12 months is to continue acquiring long-lived assets while preserving our financial strength. We will focus on achieving these goals through acquisitions from the parties with which SOG has relationships as well as with our affiliates. Additional goals during the next twelve months include: developing organic growth opportunities in our existing asset base, divesting our interest in our MidContinent assets and reducing our general and administrative expenses.

We expect that the current business climate in the midstream sector will present us with external opportunities to acquire additional long-lived assets, either directly or indirectly.

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, 2015, 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, 2014, which was filed with the SEC on March 5, 2015. 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 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

See Note 2 to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas exploration, development and 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. Geological, geophysical and dry hole costs relating to unsuccessful exploratory wells are charged to expense as 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. The 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 16 to the consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

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 7 to our consolidated financial statements for additional information.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Impairment is deemed to have occurred if a lease is going to expire prior to any planned drilling on the leased property. Valuation allowances based on average lease lives are maintained for the value of unproved properties. For our concession in Osage County, Oklahoma, we assess it for impairment on a quarterly basis, and if it is considered impaired, a charge to expense is made when such impairment is deemed to have occurred.

Oil, Natural Gas and Natural Gas Liquids Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil, natural gas and natural gas liquids 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 reserve reports prepared by NSAI, an independent petroleum engineering firm, and Ryder Scott, an independent oil and natural gas consulting firm. On an annual basis, our proved reserve estimates and the reserve report prepared by NSAI and Ryder Scott are reviewed by the audit committee of our board of directors and our board of directors. Our financial statements for 2014 were prepared using NSAI's estimates of our proved reserves. Our financial statements for 2015 were prepared using NSAI's and 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. We prepared our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. 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.

Revenue Recognition

Sales are recognized when oil, natural gas and NGLs have been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Oil, natural gas and NGLs are generally sold on a monthly basis. Most of the contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a specific tank battery, gathering or transmission line, quality of oil, natural gas and NGLs, and prevailing supply and demand conditions, so that the price of the oil, natural gas and NGLs fluctuates to remain competitive with other available oil, natural gas and NGLs supplies. As a result, revenues from the sale of oil, natural gas and NGLs will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil, natural gas and NGLs contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no material gas imbalance positions at December 31, 2015 and 2014.

Revenues relating to the gathering and transportation sales of oil and natural gas are recognized in the period service is provided. Under these arrangements, 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.

Hedging Activities

We have implemented a hedging program to limit our exposure to changes in commodity prices or basis differentials for our oil and natural gas sales and to mitigate the impact of volatility of changes in the LIBOR interest rate on the interest payments for our debt. We do not enter into speculative trading positions.

We account for all our open derivatives as mark-to-market activities using the mark-to market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions "Risk management assets" and "Risk management liabilities." We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of operations under the captions "Natural gas sales" and "Oil sales", which comprise our total revenues for commodity derivatives. Settled interest rate swaps are recognized as "Interest expense" on our consolidated statement of operations.

We experience earnings volatility as a result of using the mark-to-market accounting method. This accounting treatment can cause earnings volatility as the positions related to future oil and natural gas production or future interest payments are marked-to-market. These non-cash unrealized gains or losses are included in our current Statement of Operations until the derivatives are cash settled as the commodities are produced and sold or the interest is paid. Increases in the market price of oil or natural gas and interest rates relative to the fixed future prices for our hedges, result in unrealized, non-cash mark-to-market losses on those derivatives and lower reported net income. Decreases in the market price of oil or natural gas or interest rates relative to the fixed future prices for our hedges, result in unrealized, non-cash mark-to-market gains on those derivatives and higher reported net income. Although these gains and losses are required to be reported immediately in earnings as market prices change, the fair value of the related future physical transaction is not marked-to-market and therefore is not reflected as revenues or expenses or as an accounts receivable or accounts payable in our financial statements. This mismatch impacts our reported results of operations and our reported working capital position until the derivatives are cash settled and the future physical transaction occurs. Upon cash settlement of the derivatives, the sale of the physical commodity or interest payment at then-current market prices offsets the previously reported mark-to-market gains or losses such that the cumulative net cash realized results in a net sale of the physical oil and natural gas production or interest payment at the fixed future prices for our hedge. When our derivative positions are cash settled, the realized gains and losses of those derivative positions are included in our statement of operations as natural gas sales, oil and natural gas liquids sales, or interest expense depending on the derivative.

If we were to account for our derivatives as cash flow hedges, we would record changes in the fair value of derivatives designated as hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we would reclassify the amounts recorded in other comprehensive income into earnings. We would record the ineffective portion of changes in the fair value of derivatives used as hedges immediately in earnings. When amounts for hedging activities are reclassified from "Accumulated other comprehensive income (loss)" on the balance sheet to the Statement of Operations, we would record settled oil and natural gas derivatives as "Oil and gas sales" and settled interest rate swaps as "Interest expense (income)."

Recent Accounting Pronouncements and Accounting Changes

See Note 2 to our consolidated financial statements included in this report for information on new accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

As a smaller reporting company, we are not required to provide the information required by this item.

Item 8. Financial Statements and Supplementary Data

The Reports of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required to be filed under this item are presented in "PART IV. Item 15. Exhibits and Financial Statement Schedules" of this Annual Report on Form 10-K, and are incorporated herein by reference.

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

None.

Item 9A. Controls and Procedures

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

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

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") of our general partner have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2015 (the "Evaluation Date"). Based on such evaluation, the CEO and the CFO have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and is accumulated and communicated to our management, including the CEO and the CFO of our general partner, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2015, 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.

The Dodd-Frank Act provides smaller reporting companies with a permanent exemption from the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes-Oxley Act. We utilized this exemption under the Dodd-Frank Act for the years ended December 31, 2015 and 2014. We still disclosed management's assessment of the effectiveness of internal control over financial reporting as required in Section 404(a) of the Sarbanes-Oxley Act. The use of this exemption was reviewed and approved by our audit committee.

Reports of Management

Financial Statements

The management of the general partner of Sanchez Production Partners LP ("our") 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 of the board of directors of our general partner, 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 of directors of our general partner 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* 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 of directors of our general partner 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, 2015.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table shows information for members of the board of directors and executive officers of our general partner as of March 30, 2016. All of the directors of our general partner are elected by Manager, as the sole member of our general partner. Members of the board of directors hold office until their successors have bene 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 of directors of our general partner.

Name	Age	Position with Sanchez Production Partners GP LLC
Alan S.Bigman	48	Independent Director
Kirsten A. Hink	49	Chief Accounting Officer
Jack Howell	29	Director
Richard S. Langdon	65	Independent Director
G.M. Byrd Larberg	63	Independent Director
Antonio R. Sanchez, III	43	Director; Chairman of the Board
Eduardo A. Sanchez	36	Director
Patricio D. Sanchez	35	Director; Chief Operating Officer
Luke R. Taylor	38	Director
Charles C. Ward	55	Chief Financial Officer, Treasurer, and Secretary
Gerald F. Willinger	48	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 of our general partner's board of directors and is the Chairman of the Audit Committee of our general partner's board of directors. Mr. Bigman is currently co-founder and Director of VistaTex Energy LLC, a privately held company created in 2010 to produce oil and natural gas from mature properties in the U.S. He was most recently Director, Capital Markets and M&A of KCAD Deutag, an oilfield services company based in Aberdeen, UK, from September 2011 to December 2012, where he was responsible for reorganizing and staffing the company's finance, corporate development and tax functions. From June 1996 to March 1998, Mr. Bigman was Senior Vice President of Access Industries, a privately held, U.S.-based industrial group with worldwide holdings. 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, based in Moscow, Russia, and then as Vice President and Director of Corporate Finance for SUAL, a large Russian aluminum smelter, from September 2003 to September 2004. From September 2004 until December 2005, Mr. Bigman rejoined Access Industries as Senior Vice President, Investment and was based in London. In January 2006, Mr. Bigman was appointed Chief Financial Officer of Basell Polyolefins, an international chemicals company based in Hoofddorp, The Netherlands, where he served until January 2008. In January 2008, Mr. Bigman became the Chief Financial Officer of LyondellBasell Industries, a successor company to Basell Polyolefins and Lyondell, which had been merged. Mr. Bigman was Chief Financial Officer of LyondellBasell until August 2009, when he took on a consulting role with the company, and exited the company in March 2010. Prior to assuming the role of Chief Financial Officer at Basell Polyolefins, Mr. Bigman was on the company's board of directors, where he served as a member of the audit and compensation committees.

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. Prior to joining Sanchez Energy, 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.

Jack Howell was elected as a director of our general partner on October 14, 2015. Mr. Howell has been a Managing Director with Stonepeak Infrastructure Partners (“Stonepeak”) since 2015. 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 Conflicts Committee of our general partner’s board of directors. Mr. Langdon is also currently the President, Chief Executive Officer and Chairman of KMD Operating Company LLC (“KMD Operating”), a position held since November 2011, a privately held exploration and production company. Mr. Langdon has been serving as the Interim President and Chief Executive Officer of Gasco Energy, Inc., a publicly traded exploration and production company, since May 2013. Mr. Langdon has also served as a Director of Gasco Energy, Inc. since 2003. Mr. Langdon was the President and Chief Executive Officer of Matris Exploration Company L.P., a privately held exploration and production company, or Matris Exploration, from July 2004 and Executive Vice President and Chief Operating Officer of KMD Operating from August 2009 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 exploration and 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 and 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 of our general partner’s board of directors and is the Chairman of the Conflicts Committee of our general partner’s board of directors. Mr. Larberg currently performs consulting services on an individual basis. 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, where he serves on the Financial Development Committee and as Past Chairman of the Board Campaign. Previously, 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, ending as Vice President of Exploration and Production, Africa and Latin America for Pecten International, an affiliate of Shell Oil Company, from 1993 to 1996. During his tenure he also served as Exploration Manager for Shell Western E&P Domestic USA Onshore, including the Mid Continent, from 1990 to 1993, and as the Division Exploration Manager for the Gulf Coast Division covering offshore Louisiana from 1987 to 1990. After successfully completing a fourteen month special assignment to the Director of New Business Development for Royal Dutch Shell’s Worldwide Deepwater efforts, 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 March 2006 following the company’s purchase by ConocoPhillips. Since such time, he has occasionally consulted in the areas of technical and portfolio management for exploration companies, including Pemex, Maersk, ONGC and Glopetrol. Mr. Larberg was a director of Duma Hydrocarb Energy Corporation, a publicly traded exploration and production company, from 2014 to 2015.

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 our general partner's board of directors. He has served as the Chief Executive Officer of Sanchez Energy, a publicly traded exploration and production company, 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 12 years. Mr. Sanchez, III is also the President of SOG, which he joined in October 2001, as well as the President of SEP Management I, LLC and a Managing Director of Sanchez Energy Partners I, LP. In his capacities as a director and officer of these companies, Mr. Sanchez, III manages 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. He has served as the President of Sanchez Energy since October 1, 2015. He has served as President and Chief Executive Officer of Sanchez Resources LLC ("Sanchez Resources"), an oil and gas company, since 2010. Sanchez Resources holds and operates properties throughout Louisiana and Mississippi, including a substantial position in the core of the Tuscaloosa Marine Shale.

Patricio D. Sanchez was elected 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 also been the managing member of Santerra Holdings, LLC, an oil and gas exploration and production company, since February 2012.

Luke R. Taylor was elected as a director of our general partner in October 2015. Mr. Taylor has been a Senior Managing Director with Stonepeak since 2011. He has been investing in infrastructure for over 14 years, sits on the board of Paradigm Energy Partners, Casper Crude to Rail Holdings, and Energizing Co., and is a former director of Orion Holdings and Northstar Renewable Power. Prior to joining Stonepeak, Mr. Taylor was a Senior Vice President with Macquarie Capital based in New York from 2005 to 2011.

Charles C. Ward was elected Chief Financial Officer and Secretary of our general partner in March 2015 and re-elected Treasurer in March 2016. 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 is currently a Managing Partner of Sanchez Capital Advisors, LLC and Manager and Co-founder of Sanchez Resources since February 2010. Mr. Willinger currently serves as a Director of Sanchez Resources. From 1998 to 2000, Mr. Willinger was an investment banker with Goldman, Sachs & Co. Mr. Willinger served in various private equity investment management roles at MidOcean Partners, LLC and its predecessor entity, DB Capital Partners, LLC, from 2000 to 2003 and at the Cypress Group, LLC from 2003 to 2006. Prior to joining Sanchez Capital Advisors, LLC, Mr. Willinger was a Senior Analyst for Silver Point Capital, LLC, a credit-opportunity fund, from 2006 to 2009.

Messrs. Howell and Taylor were elected to the board of directors of our general partner in October 2015 LLC pursuant to a board representation and standstill agreement entered into in connection with our issuance of Class B preferred units to Stonepeak Catarina Holdings LLC. Pursuant to the agreement, we and our general partner agreed to permit Stonepeak to designate two persons to serve on our general partner's board of directors. 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 of directors 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 Board of Directors

The sole member of our general partner elects all of the persons to our board of directors, except for two persons who are appointed by holders of our Class B preferred units. 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 of directors of our general partner. 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 upstream 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. Mr. Bigman is independent of SOG.

- Mr. Langdon brings to the board of directors of our general partner considerable financial and managerial experience in the energy industry as well as his entrepreneurial abilities, which are valuable to a small growing company such as us. He has served as the Chief Financial Officer of EEX Corporation, a publicly traded exploration and 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 is 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 Energy, Inc., a publicly traded exploration and production company until he was named Gasco's President and Chief Executive Officer.

- Mr. Larberg brings to the board of directors of our general partner significant technical, operational and financial management experience in the oil and natural gas industry. His background, which includes extensive geology training and education and encompasses a distinguished career at Shell Oil Company and Burlington Resources, provides a unique perspective on the dynamics of the oil and natural gas exploration and production industry. He has considerable governance experience, having previously served on the boards of Meridian Resources, a Houston-based exploration company acquired by Alta Mesa in 2010, Risco Resources, a small independent exploration company headquartered in Jakarta, Indonesia, and 3GIG, an exploration-focused software firm headquartered in Houston, Texas. He is also active on the Board of the Houston Metropolitan YMCA, where he serves on the Financial Development Committee and as Past Chairman of the Board Campaign, which raised $6.5 million for underprivileged children under his leadership. Taken together, this wealth of experience is invaluable to our board as we look to grow the Company.

- Mr. Sanchez, III brings to the board of directors of our general partner substantial upstream oil and gas/energy industry experience in both public and private entities. In his current capacity as Chief Executive Officer of Sanchez Energy, he brings the perspective of leading a quickly growing, publicly-traded upstream company focused on asset value maximization and the creation of shareholder value. In his current capacity as Co-President of SOG, he brings particular expertise in operating multiple upstream oil and natural gas entities through a shared service model.
- Mr. Eduardo Sanchez brings to the board of directors of our general partner substantial upstream oil and gas/energy industry experience in both public and private entities. In his capacity as President of Sanchez Energy, he brings the perspective of leading a quickly growing publicly-traded upstream company focused on asset value maximization and the creation of shareholder value. In his capacity as President of SOG, he brings particular expertise in operating multiple upstream oil and natural gas entities through a shard service model.
- Mr. Patricio Sanchez brings to the board of directors of our general partner substantial upstream oil and gas/energy industry experience in both public and private entities. In his current capacity as Co-President of SOG, he brings particular expertise in operating multiple upstream oil and gas entities through a shared service model.
- Mr. Willinger brings to the board of directors of our general partner substantial experience in risk management, finance and negotiated transactions in the energy industry. He has a valuable perspective on upstream 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 of directors of our general partner 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 of directors of our general partner significant investment experience in energy and infrastructure companies.

Committees of the Board of Directors

The board of directors of our general partner has two standing committees: an audit committee and a conflicts committee. We do not have a compensation committee, but rather the board of directors of our general partner approves equity grants to directors, officers, employees and service providers.

Audit Committee

As described in the audit committee 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 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 of directors of our general partner established. In doing so, it will be 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 of directors of our general partner 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 MKT listing standards.

Conflicts Committee

Under our partnership agreement, the board of directors of our general partner has appointed a conflicts committee composed of the independent directors, G. M. Byrd Larberg, chairman, Alan Bigman and Richard Langdon, to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of a conflict of interest is fair and reasonable to us. 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 MKT, the Exchange Act and other federal securities laws. Any matter approved by the conflicts committee is conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties that it may owe us or our unitholders.

Other

We maintain on our website, www.sanchezpp.com, copies of the charters of each of the committees of the board of directors of our general partner (except the conflicts committee which does not have a charter), as well as copies of the Corporate Governance Guidelines and Code of Business Conduct and Ethics that are applicable to us and our general partner. Copies of these documents are also available in print 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, we believe that during 2015 all Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner, except for one Form 4 filed late by Stephen R. Brunner, the former President, Chief Executive Officer and Chief Operating Officer of our general partner, in connection with his termination of employment.

Certifications

The NYSE MKT requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by the Partnership of the NYSE MKT's corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE MKT, we last provided such a certification on April 21, 2015. The certifications of the Chief Executive Officer and Chief Financial Officer required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this Annual Report of our general partner on 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 of directors and executive officers make decisions on our behalf. The executive officers of our general partner are employed by SOG and manage the day-to-day affairs of our business.

Summary Compensation Table

The following table sets forth the compensation of our named executive officers (which are each chief executive officer and the next two most highly compensated officers of our general partner) for 2015 and 2014:

Name and Principal Position	Year	Salary	Cash Bonus	Unit Awards (a)	All Other Compensation (b)	Total
Gerald F. Willinger	2015	$ —	$ 1,200,000	$ 571,841	$ 43,883	$ 1,815,724
Chief Executive Officer [c][d]	2014	$ —	$ —	$ —	$ —	$ —
Stephen R. Brunner	2015	$ 90,927	$ —	$ 63,535	$ 3,862,758	$ 4,017,220
Former President, Chief Executive Officer, and Chief Operating Officer [b][e]	2014	$ 350,097	$ 700,350	$ 2,075,174	$ 11,771	$ 3,137,392
Patricio D. Sanchez	2015	$ —	$ 800,000	$ 580,935	$ 25,397	$ 1,406,332
Chief Operating Officer [d][f]	2014	$ —	$ —	$ —	$ —	$ —
Charles C. Ward	2015	$ 287,375	$ 409,613	$ 231,182	$ 30,676	$ 958,846
Chief Financial Officer, Treasurer and Secretary [d][g]	2014	$ 262,573	$ 393,860	$ 823,890	$ 11,256	$ 1,491,579

(a) The amounts shown in this column represent the aggregate grant date fair value of the restricted units granted under the Sanchez Production Partners LP Long-Term Incentive Plan, computed in accordance with FASB ASC Topic 718, for service as executive officers based on the $14.00 price per common unit on December 1, 2015, the date of grant. In addition, Messrs. Willinger and Sanchez received common units as director fees in the amount of 52,631 and 56,526, respectively, based on the $1.90 and $1.93 price per common unit on March 31, 2015 and June 30, 2015, the respective dates of grant.

(b) The amount in this column reflects the amount of matching contributions made to Messrs. Brunner ($3,637) and Ward ($10,400) under our 401k plan and the cost of life insurance for our executive officers. The amount for Mr. Brunner also includes a $2,404,932 severance amount paid in 2015 in connection with the termination of his employment pursuant to the terms of his employment agreement with us. The amounts for Messrs. Willinger and Sanchez also include director fees paid in cash in the amount of $43,286 and $24,500, respectively. The amount for Mr. Ward includes $16,805 for payout of accrued vacation.

(c) Mr. Willinger was elected as Interim Chief Executive Officer of our general partner in April 2015 and as Chief Executive Officer in December 2015.

(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. Brunner's employment terminated in March 2015.

(f) Mr. Sanchez was elected Chief Operating Officer in May 2015.

(g) In January 2016, Mr. Ward's employment with us was mutually terminated, and Mr. Ward became an employee of SOG. Mr. Ward has remained as the Chief Financial Officer and Secretary of our general partner.

Employment Agreements

None of the executive officers of our general partner have employment agreements. Until January 2016, Mr. Ward had an employment agreement with us pursuant to which he received his compensation. For 2015, Mr. Ward's base salary had been established at $273,075, with a 150% target bonus.

In January 2016, we and Mr. Ward mutually agreed to terminate Mr. Ward's employment agreement in connection with Mr. Ward's termination of employment with our subsidiary and his becoming an employee of SOG. In connection with the employment transition, and pursuant to the terms of his employment agreement that provided for the payment as a result of our conversion from a limited liability company to a limited partnership, Mr. Ward received a cash severance payment of $1,363,375, the accelerated vesting of 25,641 restricted units, the nonforfeiture of any benefits under nonqualified deferred compensation plans, and the established right to continued health benefits. In exchange, Mr. Ward provided a release of all claims against us, our general partner, Manager, SOG and other affiliates.

Outstanding Equity Awards at Fiscal Year-End 2015

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units on NYSE MKT at December 31, 2015 for the named executive officers:

Name	Number of Units Not Vested	Fair Market Value of Units Not Vested[a]
Gerald F. Willinger	33,703 [b]	479,257
Stephen R. Brunner	—	—
Patricio D. Sanchez	33,703 [b]	479,257
Charles C. Ward	25,641 [c]	364,615
	15,000 [b]	213,300

(a) Amounts are based on the closing price of our common units of $14.22 as reported on the NYSE MKT on December 31, 2015.

(b) Reflects restricted units granted under the Sanchez Production Partners LP Long-Term Incentive Plan (the "Plan") on December 1, 2015. The units vest pro-rata over a three-year period. 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.

(c) Reflects notional units granted on December 18, 2014. The notional units converted on a one-for-one basis into restricted common units upon unitholder approval of our conversion into a limited partnership. The vesting of all of these units was accelerated in January 2016 in connection with Mr. Ward's transition of employment to SOG.

Compensation of Directors

The board of directors of our general partner has approved the following compensation program for its directors:

- 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 of directors 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; and
- 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.

The following table sets forth a summary of the 2015 compensation for the directors of our general partner's board of directors, 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	Total
Alan S. Bigman	$ 87,500	$ 100,000	$ —	$ 187,500
Jack Howell [(b)]	$ —	$ —	$ —	$ —
Richard S. Langdon [(c)]	$ 143,929	$ 100,000	$ —	$ 243,929
G. M. Byrd Larberg	$ 80,536	$ 100,000	$ —	$ 180,536
Antonio R. Sanchez, III	$ 41,786	$ 571,842	$ —	$ 613,628
Eduardo A. Sanchez	$ 24,500	$ 696,011	$ —	$ 720,511
Luke R. Taylor [(b)]	$ —	$ —	$ —	$ —

(a) The amounts shown in this column represent the aggregate grant date fair value of the units granted under the Sanchez Production Partners LP Long-Term Incentive Plan, computed in accordance with FASB ASC Topic 718, based on the $19.00 price per common unit on March 31, 2015, the date of grant for all directors, except for Mr. Eduardo Sanchez, whose grant was made on June 30, 2015 when he was elected to the board of directors and the price per common unit was $19.30. In addition, this column reflects a grant made to Mr. Sanchez, III and Mr. Eduardo Sanchez on December 1, 2015 when the price per common unit was $14.00 for services rendered to us as the Chairman of the Board of our general partner and as an employee of SOG, respectively. None of the directors had any outstanding awards as of December 31, 2015.

(b) As the designated directors appointed by Stonepeak, Messrs. Howell and Taylor waived any director fees to which they were otherwise entitled.

(c) Mr. Langdon received a one-time cash payment of $50,000 for prior service to the board of managers of Sanchez Production Partners LLC.

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 held by:

- each unitholder who is a beneficial owner of more than 5% of our outstanding units;
- each of the directors of our general partner's board of directors each named executive officer; and
- the directors and executive officers of our general partner as a group.

The amounts and percentage of common units, Class A preferred 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 3,240,812 common units, 11,409,131 Class A preferred units and 19,444,445 Class B preferred units outstanding. 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. Unless otherwise set forth below, the address of all of all beneficial owners is c/o Sanchez Production Partners LP, 1000 Main Street, Suite 3000, Houston, Texas 77002. Ownership amounts are as of March 23, 2016.

Name of Beneficial Owner	Common Units Beneficially Owned		Class A Preferred Units Beneficially Owned[1]		Class B Preferred Units Beneficially Owned[1]		Percentage of Total Units Beneficially Owned[1]
	Number	Percentage	Number	Percentage	Number	Percentage	
Stonepeak Catarina Holdings LLC[2]	—	—	—	—	19,444,445	100 %	56.9 %
Raging Capital Management, LLC.[3]	—	—	5,552,718	47.5 %	—	—	16.3 %
HITE[4]	—	—	5,552,719	47.5 %	—	—	16.3 %
Dorsey Gardner[5]	247,738	8.2 %	—	—	—	—	*
UBS Group A6[6]	175,242	5.8 %	—	—	—	—	*
Antonio R. Sanchez, Jr.[7]	157,717	5.2 %	—	—	—	—	*
Alan S. Bigman	5,263	*	—	—	—	—	*
Stephen R. Brunner[8]	119,980	4.0	—	—	—	—	*
Kirsten A. Hink	12,500	*	—	—	—	—	*
Jack Howell	—	—	—	—	—	—	—
Richard S. Langdon	10,810	*	—	—	—	—	*
G. M. Byrd Larberg	5,263	*	—	—	—	—	*
Antonio R. Sanchez, III[9]	109,726	3.6 %	—	—	—	—	*
Eduardo A. Sanchez[10]	72,389	2.4 %	—	—	—	—	*
Patricio D. Sanchez[11]	72,994	2.4 %	—	—	—	—	*
Luke R. Taylor	—	—	—	—	—	—	—
Charles C. Ward	67,132	2.2 %	—	—	—	—	*
Gerald F. Willinger[12]	49,472	1.6 %	—	—	—	—	*
All directors and executive officers as a group (12 persons)[13]	405,549	13.2 %	—	—	—	—	1.2 %

* Less than 1%

(1) All of the Class A preferred units outstanding as of March 31, 2016 will convert into our common units. The holder of Class B preferred units has the right to convert such units into our common units at any time.

(2) Ownership data as reported on Schedule 13D filed on October 26, 2015 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 Class B preferred units.

(3) Ownership data of the common units as reported on Schedule 13G/A filed on November 10, 2015 by Raging Capital Master Fund, Ltd., Raging Capital Management, LLC and William C. Martin. The principal business address of each of Raging Capital Management, LLC and Mr. Martin is Ten Princeton Avenue, P.O. Box 228, Rocky Hill, New Jersey 08553; and the principal business address of Raging Capital Master Fund, Ltd. Is c/o Ogier Fiduciary Services (Cayman) Limited, 89 Nexus Way, Camana Bay, Grand Cayman KY 1-9007, Cayman Islands. The filing lists each filing person as having shared voting and dispositive power over the common units.

(4) HITE Hedge LP owns 2,037,847 Class A preferred units, HITE MLP LP owns 1,443,707 Class A preferred units, HITE Hedge QP LP owns 1,365,969 Class A preferred units, and HITE MLP Advantage LP owns 705,196 Class A preferred units. The address of each unitholder is 300 Washington Street, Suite 308, Newton, MA 02465.

(5) Ownership data as reported on Schedule 13G filed on February 9, 2016 by Dorsey R. Garner. The principal business address of the reporting person is 401 Worth Ave, Palm Beach, Florida 33480. The filing lists the filing person as having shared voting and dispositive power over the common units.

(6) Ownership data as reported on Schedule 13G filed on February 9, 2016 by UBS Group AG directly and on behalf of certain subsidiaries. The principal business address of the reporting person is Bahnhofstrasse 45, PO Box CH-8021, Zurich, Switzerland. The filing lists the filing person as having shared voting and dispositive power over the common units.

(7) Ownership data as reported on Schedule 13D/A filed on March 10, 2016. The address of the filing person is 1000 Main Street, Suite 3000, Houston, Texas 77002. The filing lists the filing person as having sole voting and dispositive power over 61,431 common units and shared voting and dispositive power over 94,126 common units. The filing person has the right to acquire 2,160 common units upon the Partnership's payment of the services fee to Manager for the quarter ended December 13, 2015 pursuant to the Services Agreement.

(8) Ownership data reported on Form 4 filed on April 17, 2015.

(9) Mr. Sanchez owns 54,804 common units. Mr. Sanchez is co-trustee of a trust that holds 19,602 common units, of which Mr. Sanchez shares voting and dispositive power. Mr. Sanchez is a co-manager of SOG, which owns 35,320 common units and of which Mr. Sanchez shares voting and dispositive power. Mr. Sanchez has the right to acquire 14,036 common units upon the Partnership's payment of the service fee to Manager for the quarter ended December 31, 2015 pursuant to the Services Agreement.

(10) Mr. Sanchez owns 52,787common units. Mr. Sanchez is co-trustee of a trust that holds 19,602 common units, of which Mr. Sanchez shares votin g and dispositive power. Mr. Sanchez has the right to acquire 14,036 common units upon the Partnership's payment of the service fee to Manager for the quarter ended December 31, 2015 pursuant to the Services Agreement.

(11) Mr. Sanchez owns 53,392common units. Mr. Sanchez is co-trustee of a trust that holds 19,602 common units, of which Mr. Sanchez shares voting and dispositive power. Mr. Sanchez has the right to acquire 14,036 common units upon the Partnership's payment of the service fee to Manager for the quarter ended December 31, 2015 pursuant to the Services Agreement.

(12) Mr. Willinger owns 49,472 common units. Mr. Willinger has the right to acquire 4,377 common units upon the Partnership's payment of the service fee to Manager for the quarter ended December 31, 2015 pursuant to the Services Agreement.

(13) Certain officers and directors have the right to acquire 46,485 common units upon the Partnership's payment of the service fee to Manager for the quarter ended December 31, 2015 pursuant to the Services Agreement.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information for our only equity compensation plan, the Sanchez Production Partners LP Long-Term Inventive Plan, as of December 31, 2015:

	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
Plan Category			
Equity compensation plans approved by security holders[a]	—	$ —	222,638
Equity compensation plans not approved by security holders	—	$ —	—
Total	—	$ —	222,638

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

Manager

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, Eduardo A. Sanchez, Patricio D. Sanchez 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, 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, professionals and acquisition, disposition and financing services. 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) a $1,000,000 administrative fee, with $500,000 paid on May 8, 2014 and $500,000 paid on July 1, 2014, the date that Manager provided notice of its commitment to provide services under the services agreement, (iii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iv) 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. During the year ended December 31, 2015, we paid $9.9 million to Manager under the Services Agreement. During the year ended December 31, 2014, we paid $6.0 million to Manager under the Services Agreement and issued 5,956 common units to Manager pursuant to the Services Agreement in connection with Manager's election to receive payment of its fee for the quarter ended September 30, 2014 in common units rather than cash, with such issuance being in lieu of paying a fee of $165,582 in cash, or $12.78 per common unit.

In connection with our conversion from a limited liability company to a limited partnership in March 2015, all of our incentive distribution rights were granted to Manager. Pursuant to the terms of our partnership agreement, if, for any quarter, we have distributed cash from operating surplus to our common unitholders in an amount equal to the minimum quarterly distribution, then we will make additional distributions from operating surplus for that quarter among the common unitholders and Manager (as the holder of our incentive distribution rights) in the following manner:

- first, 100% to all common unitholders, pro rata, until each unitholder receives a total of $0.575 per unit for that quarter;
- second, 87.0% to all common unitholders, pro rata, and 13.0% to the holders of our incentive distribution rights, until each unitholder receives a total of $0.625 per unit for that quarter;
- third, 77.0% to all common unitholders, pro rata, and 23.0% to the holders of our incentive distribution rights, until each unitholder receives a total of $0.875 per unit for that quarter; and
- thereafter, 64.5% to all common unitholders, pro rata, and 35.5% to the holders of our incentive distribution rights.

No incentive distribution payments have been made since their date of issuance.

SOG

SOG provides services to us through a contractual relationship with SP Holdings. Antonio R. Sanchez, III, Eduardo A. Sanchez 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 sole member 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 the Executive Vice President.

In May 2014, we entered into a Contract Operating Agreement with SOG (the "Operating Agreement") pursuant to which SOG either provides services to operate, develop and produce our oil and natural gas properties or engages a third-party operator to do so, other than with respect to our properties in the Mid-Continent region. In connection with providing services under the Operating Agreement, SOG will be reimbursed for all direct charges under COPAS. Aside from reimbursed costs, no amounts have been paid to SOG under the Operating Agreement during the years ended December 31, 2015 and 2014.

In May 2014, we entered into a Transition Agreement with SOG and Manager (the "Transition Agreement") pursuant to which we agreed to make available to Manager and SOG certain of our employees for SOG or Manager to provide services under the Services Agreement and Operating Agreement. No compensation was paid by any party for the provision or use of employees under the Transition Agreement. All employees remained under our day-to-day control, and we retained the right to terminate employees and had no obligation to hire new employees. SOG had the right to hire any of our employees and thereafter, SOG was responsible for all costs and expenses for such employees. As of July 1, 2014, all of our employees located in the Houston office became employees of SOG, except for the former Chief Executive Officer and the Chief Financial Officer. In January 2016, the Chief Financial Officer's employment with us was mutually terminated and he became an employee of SOG.

In May 2014, we and certain of our subsidiaries entered into a Geophysical Seismic Data Use License Agreement with SOG (the "License Agreement") pursuant to which SOG provides us with a non-exclusive, royalty-free license to use seismic, geophysical and geological information relating to our oil and natural gas properties that is proprietary to SOG and not restricted by agreements that SOG has with landowners or seismic data vendors. No amounts are payable under the License Agreement.

Sanchez Energy

We have entered into several transactions with Sanchez Energy since January 1, 2015. Antonio R. Sanchez, Jr. is a director and Executive Chairman of the Board of Sanchez Energy, and Antonio R. Sanchez, III, is a director and Chief Executive Officer of Sanchez Energy. In addition, Eduardo Sanchez is the 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 ownership of Sanchez Energy's common stock as of February 28, 2016 by Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, and Eduardo Sanchez was (9.7%), (4.1%), and (2.8%), respectively.

In March 2015, we entered in a purchase and sale agreement with Sanchez Energy to purchase oil and gas properties for total consideration of $85.0 million. After $1.4 million in normal and customary closing adjustments, consideration paid at closing consisted of $81.6 million cash paid by us to Sanchez Energy and 105,263 of our common units issued to Sanchez Energy with an aggregate consideration value of $2,000,000. In connection with the purchase agreement, we entered into a registration rights agreement with Sanchez Energy pursuant to which we granted certain registration rights related to the common unit consideration received.

In September 2015, we entered into a purchase and sale agreement with Sanchez Energy to purchase all of the seller's issued and outstanding membership interests in Catarina Midstream, LLC for total consideration of approximately $345.8 million in cash, subject to closing and post-closing adjustments. Catarina Midstream owned the Catarina gathering system and the common units issued in connection with the March 2015 acquisition. The transaction closed in October 2015. Pursuant to the purchase agreement, Sanchez Energy has granted us, for a period of 15 years after the closing date, a right of first offer on any equipment, pipelines, tanks and tangible personal property used for the gathering, transportation and plant separation of hydrocarbons from wells, which Sanchez Energy or any subsidiary thereof proposes to transfer to any unaffiliated person.

In October 2015, we entered into a 15-year gas gathering and processing agreement with Sanchez Energy, pursuant to which Sanchez Energy agreed to tender all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres in the Western Catarina area of the Eagle Ford Shale in Texas for processing and transportation through the Catarina gathering system, with the potential to tender additional volumes outside of the dedicated acreage. During the first five years of the term, Sanchez Energy is required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. Sanchez Energy is required to pay gathering and processing fees of $0.96 per barrel for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through the Catarina gathering system, in each case, subject to an annual escalation for a positive increase in the consumer price index. For the year ended December 31, 2015, Sanchez Energy paid us approximately $7.5 million pursuant to the terms of the gathering and processing agreement.

Class A Preferred Unit Issuance

In March 2015, we entered into purchase agreement with, among others, Raging Capital Master Fund, Ltd. pursuant to which we sold, and Raging Capital purchased, 5,156,250 of our newly created Class A preferred units in a privately negotiated transaction for an aggregate cash purchase price of $1.60 per Class A preferred unit resulting in gross proceeds to us of $8,250,000. Pursuant to the terms of our partnership agreement, 128,906, 132,129 and 135,433 additional Class A preferred units were issued to Raging Capital in August 2015, November 2015 and February 2016 on account of paid-in-kind interest due and payable with respect to the units for the quarters ended June 30, 2015, September 30, 2015 and December 31, 2015, respectively.

In March 2015, we also sold 5,468,750 Class A preferred units to HITE Hedge LP, HITE MLP LP, HITE Hedge QP LP, HITE MLP Advantage LP and Michael Brewster for an aggregate cash purchase price of $1.60 per Class A preferred unit resulting in gross proceeds to us of $8,750,000. Pursuant to the terms of our partnership agreement, 136,716, 140,139 and 143,642 additional Class A preferred units were issued to the these holders of Class A preferred units in

August 2015, November 2015 and February 2016 on account of paid-in-kind interest due and payable with respect to the units for the quarters ended June 30, 2015, September 30, 2015 and December 31, 2015, respectively.

In March 2015, we entered into a registration rights agreement with each holder of Class A preferred units pursuant to which we agreed to register the resale of the common units issuable upon conversion of the Class A preferred units. A registration statement relating to the resale of such common units was declared effective by the SEC in July 2015.

In October 2015, we provided notice to the holders of Class A preferred units that we were electing to convert all of the Class A preferred units into common units on March 31, 2016.

Class B Preferred Unit Issuance

In October 2015, we entered into purchase agreement with Stonepeak Catarina Holdings, LLC pursuant to which we sold, and Stonepeak purchased, 19,444,445 of our newly created Class B preferred units in a privately negotiated transaction for an aggregate cash purchase price of $18.00 per Class B preferred unit resulting in gross proceeds to us of $350,000,010. Pursuant to the terms of our partnership agreement, a distribution of $7.4 million was made to Stonepeak in February 2016.

In October 2015, we entered into a registration rights agreement with Stonepeak pursuant to which we agreed to register, upon Stonepeak's request, the resale of the common units issuable upon conversion of the Class B preferred units. In addition, we and our general partner entered into a board representation and standstill agreement with Stonepeak pursuant to which we and our general partner have agreed to permit Stonepeak to designate two persons to serve on the board of directors of our general partner.

Restricted Unit Grant

In December 2015, we granted a restricted unit award of 33,703 common units to Antonio R. Sanchez, Jr. Unless otherwise accelerated by the administrator of our long-term incentive plan and subject to certain other conditions such as continued service by Mr. Sanchez, such restricted units will vest pro-rata over a three-year period. 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 Mr. Sanchez is no longer an officer, employee, consultant or director of us, our general partner, any of affiliates thereof or any other person performing bona fide services for us and our subsidiaries. Based on the $14.00 closing price of our common units as reported on the NYSE MKT on the date of grant, the value of the restricted units was $471,842.

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, 2015 and 2014.

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, 2015 and 2014 were $678,000 and $605,356, respectively.

Audit-Related Fees. The aggregate fees billed for audit-related fees for the year ended December 31, 2015 were $160,000. There were no audit-related fees billed by KPMG for the year ended December 31, 2014.

Tax Fees. There were no tax fees billed by KPMG for the years ended December 31, 2015 and 2014.

All Other Fees. There were no other fees billed by KPMG for the years ended December 31, 2015 and 2014.

Audit Committee Pre-Approval Policies and Practices

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

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

1. Financial Statements:

Report of Independent Registered Public Accounting Firm dated March 30, 2016 of KPMG LLP

Consolidated Statements of Operations—Sanchez Production Partners LP for the two years ended December 31, 2015

Consolidated Balance Sheets—Sanchez Production Partners LP at December 31, 2015 and December 31, 2014

Consolidated Statements of Cash Flows—Sanchez Production Partners LP for the two years ended December 31, 2015

Consolidated Statements of Changes in Members' Equity/Partners' Capital—Sanchez Production Partners LP for the two years ended December 31, 2015

Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Schedules are omitted as not applicable or not required

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

Exhibit Number	Description
1.1	At Market Issuance Sales Agreement, dated as of April 17, 2015, between Sanchez Production Partners LP and MLV & Co. LLC (incorporated herein by reference to Exhibit 1.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 17, 2015, File No. 001-33147).
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).

2.4	Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson's Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on September 29, 2006, File No. 333-134995).
2.7	Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	Membership Interest Purchase and Sale Agreement, dated February 1, 2013 between Constellation Energy Partners LLC and Constellation Commodities Upstream LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on February 4, 2013, File No. 001-33147).
2.10	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).
2.11	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).
2.12	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).
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	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).

3.4	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).
3.5	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 filed by Sanchez Production Partners LP on August 14, 2015, File No. 001-33147).
3.6	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).
10.1	Class A Preferred Unit Purchase Agreement, dated as of March 31, 2015, between Sanchez Production Partners LP and the purchasers 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 April 1, 2015, File No. 001-33147).
10.2	Class A Preferred Unit Purchase Agreement, dated as of April 15, 2015, between Sanchez Production Partners LP and the purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 15, 2015, File No. 001-33147).
10.3	Class B Preferred Unit Purchase Agreement, dated as of September 25, 2015, between Sanchez Production Partners LP and the purchaser named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on September 29, 2015, File No. 001-33147).
10.4	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).
10.5	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).
10.6	Joinder, Assignment and Second Amendment to Third Amended and Restated Credit Agreement, dated as of October 14, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
10.7	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).

10.8	Exploration and Development Agreement, dated July 25, 2005, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.9	Substituted and Replaced First Amendment to the Exploration and Development Agreement, dated October 18, 2006, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.10	Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.11	Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.12	First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.13	Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson's Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.14	Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson's Bend Operating II, LLC, Robinson's Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
10.15+	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.16+	Mutual Termination, Waiver and Release, dated January 22, 2016, between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on January 27, 2016, File No. 001-33147).
*10.17+	Summary Compensation of Executive Officers of Sanchez Production Partners GP LLC.
*10.18+	Summary Compensation of Directors of Sanchez Production Partners GP LLC.
10.19	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-K filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).

10.20	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).
10.21	Geophysical Seismic Data Use License Agreement, dated May 8, 2014, between Constellation Energy Partners, LLC, certain subsidiaries thereof, and Sanchez Oil & Gas Corporation (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 8, 2014, File No. 001-33147).
10.22	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-K filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).
10.23	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).
10.24+	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).
10.25+	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).
10.26+	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).
*21.1	List of subsidiaries of Sanchez Production Partners LP.
*23.1	Consent of KPMG LLP.
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*23.3	Consent of Ryder Scott Co. LP
*31.1	Certification of Chief Executive Officer of Sanchez Production 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 Production Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer of Sanchez Production Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer and Secretary of Sanchez Production 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 Netherland, Sewell & Associates, Inc.
*99.2	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.

INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Sanchez Production Partners LP and the Board of Directors of Sanchez Production Partners GP LLC.

We have audited the accompanying consolidated balance sheets of Sanchez Production Partners LP (formerly Sanchez Production Partners LLC) and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in members' equity/partners' capital, and cash flows for the years then ended. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Sanchez Production Partners LP and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/KPMG LLP

Houston, Texas
March 30, 2016

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

	Year Ended December 31, 2015		Year Ended December 31, 2014	
Revenues				
Natural gas sales	$	19,809	$	34,458
Oil sales		35,297		40,337
Natural gas liquids sales		1,597		2,477
Gathering and transportation sales		11,725		—
Total revenues		68,428		77,272
Expenses:				
Operating expenses:				
Lease operating expenses		19,988		21,012
Transportation operating expenses		2,176		—
Cost of sales		595		1,487
Production taxes		1,792		3,200
General and administrative		26,109		16,499
Exploration costs		1,866		—
(Gain) loss on sale of assets		(111)		223
Depreciation, depletion and amortization		14,536		17,533
Asset impairments		123,860		5,424
Accretion expense		1,099		604
Total operating expenses		191,910		65,982
Other expense (income)				
Interest expense		4,207		2,076
Loss on embedded derivatives		9,982		—
Other income		(670)		(289)
Total other expenses		13,519		1,787
Total expenses		205,429		67,769
Income (loss) before income taxes		(137,001)		9,503
Income tax expense		55		—
Net income (loss)		(137,056)		9,503
Less:				
Preferred unit paid-in-kind distributions		(1,425)		—
Preferred unit dividends		(7,418)		—
Preferred unit amortization		(8,919)		—
Net income (loss) attributable to common unitholders	$	(154,818)	$	9,503
Income (loss) per unit				
Net income (loss) per unit prior to conversion				
Class A units - Basic	$	(0.38)	$	0.25
Class B units - Basic	$	(0.31)	$	0.33
Class A units - Diluted	$	(0.38)	$	0.25
Class B units - Diluted	$	(0.31)	$	0.33
Weighted Average Units Outstanding prior to conversion				
Class A units - Basic		48,451		76,326
Class B units - Basic		2,879,163		2,843,159
Class A units - Diluted		48,451		76,326
Class B units - Diluted		2,879,163		2,853,241
Net loss per unit after conversion				
Common units - Basic & Diluted	$	(50.10)	$	—
Weighted Average Units Outstanding after conversion				
Common units - Basic & Diluted		3,071,587		—

See accompanying notes to consolidated financial statements.

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

ASSETS	December 31, 2015	December 31, 2014
Current assets		
Cash and cash equivalents	$ 6,571	$ 4,238
Restricted cash	600	1,748
Accounts receivable	2,461	3,901
Accounts receivable - related entities	1,515	959
Prepaid expenses	744	1,783
Fair value of derivative instruments	21,010	14,671
Total current assets	32,901	27,300
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	732,088	651,493
Gathering and transportation assets	147,479	—
Material and supplies	1,056	1,056
Less accumulated depreciation, depletion, amortization, accretion and impairments	(653,569)	(517,239)
Oil and natural gas properties and equipment, net	227,054	135,310
Other assets		
Debt issuance costs	2,091	689
Intangible assets	199,741	—
Fair value of derivative instruments	10,008	8,158
Other non-current assets	1,596	1,790
Total assets	$ 473,391	$ 173,247
LIABILITIES AND MEMBERS' EQUITY/PARTNERS' CAPITAL		
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 7,288	$ 5,759
Accounts payable and accrued liabilities - related entities	1,035	—
Royalties payable	689	1,134
Total current liabilities	9,012	6,893
Other liabilities		
Asset retirement obligation	20,364	17,031
Embedded derivatives	193,077	—
Long-term debt	107,000	42,500
Total other liabilities	320,441	59,531
Total liabilities	329,453	66,424
Commitments and contingencies (See Note 10)		
Mezzanine equity		
Class B preferred units, 19,444,445 and zero units issued and outstanding as of December 31, 2015 and December 31, 2014, respectively	172,111	—
Members' equity / Partners' capital		
Class A units, Zero and 48,451 units issued and outstanding as of December 31, 2015 and December 31, 2014, respectively	—	1,930
Class B units, Zero and 2,877,701 units issued and outstanding as of December 31, 2015 and December 31, 2014, respectively	—	104,893
Class A preferred units, 11,409,131 and zero units issued and outstanding as of December 31, 2015 and December 31, 2014, respectively	17,112	—
Common units, 3,240,812 and zero units issued and outstanding as of December 31, 2015 and December 31, 2014, respectively	(45,285)	—
Total members' equity/partners' capital (deficit)	(28,173)	106,823
Total liabilities and members' equity/partners' capital	$ 473,391	$ 173,247

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,	
	2015	2014
Cash flows from operating activities:		
Net income (loss)	$ (137,056)	$ 9,503
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	13,250	17,533
Amortization of intangible assets	2,804	—
Asset impairments	123,861	5,424
Amortization of debt issuance costs	1,338	271
Dryhole/exploration expenses	1,866	—
Accretion expense	1,099	604
Revisions to asset retirement obligation included in DD&A	(1,518)	—
Equity earnings in affiliate	(80)	(216)
Distributions from equity affiliate	47	—
(Gain) loss from disposition of property and equipment	(111)	223
Bad debt expense	122	94
Total mark-to-market on commodity derivative contracts	(25,149)	(19,855)
Cash mark-to-market settlements on commodity derivative contracts	18,996	7,626
Unit-based compensation programs	2,454	1,298
Loss on embedded derivative	9,982	—
Costs for plug and abandon activities	(186)	—
Changes in Operating Assets and Liabilities:		
Decrease in accounts receivable	4,166	1,370
Increase in accounts receivable - related entities	(1,515)	—
Decrease in accounts payable - related entities	1,035	—
Decrease in prepaid expenses	1,039	764
(Increase) decrease in other assets	300	2
Decrease in accounts payable/accrued liabilities	(862)	(7,534)
Decrease in royalties payable	(445)	(108)
Net cash provided by operating activities	15,437	16,999
Cash flows from investing activities:		
Cash paid for acquisitions	(427,218)	(1,351)
Development of oil and natural gas properties	(2,005)	(5,865)
Proceeds from sale of assets	470	485
Distributions from equity affiliate	13	295
Net cash used in investing activities	(428,740)	(6,436)
Cash flows from financing activities:		
Proceeds from issuance of preferred units	359,500	—
Payments for offering costs	(1,756)	—
Proceeds from issuance of debt	107,000	5,750
Repayment of debt	(42,500)	(13,950)
Issuance of common units	193	—
Members' cash contributions	(1,219)	—
Repurchase of common units under repurchase program	(2,223)	—
Units tendered by employees for tax withholdings	(618)	(415)
Repurchase of Class A, Class C and Class D interests	—	(2,468)
Debt issuance costs	(2,741)	(136)
Net cash provided by (used in) financing activities	415,636	(11,219)
Net increase (decrease) in cash and cash equivalents	2,333	(656)
Cash and cash equivalents, beginning of period	4,238	4,894
Cash and cash equivalents, end of period	$ 6,571	$ 4,238
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 1,684	$ (512)
Acquisition of oil and natural gas properties in exchange for common units	935	—
Cash paid during the period for interest	2,380	1,841
Cash paid during the period for income taxes	53	(73)

See accompanying notes to consolidated financial statements.

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

	Class A Units		Class B Units		Class A Preferred Units		Common Units		Total
	Units[1]	Amount	Units[1]	Amount	Units	Amount	Units[1]	Amount	Equity/Capital
Members' Equity, December 31, 2013	161,502	$ 2,591	2,846,218	$ 96,314	—	$ —	—	$ —	$ 98,905
Units tendered by employees for tax withholding	—	—	(16,018)	(415)	—	—	—	—	(415)
Unit-based compensation programs	—	—	49,058	1,298	—	—	—	—	1,298
Cancellation of units	(113,051)	(851)	—	(1,617)	—	—	—	—	(2,468)
Net income	—	190	—	9,313	—	—	—	—	9,503
Members' Equity, December 31, 2014	48,451	1,930	2,879,258	104,893	—	—	—	—	106,823
Units tendered by employees for tax withholding	—	—	(1,557)	(21)	—	—	—	—	(21)
Net loss (January 1st - March 5th)	—	(18)	—	(905)	—	—	—	—	(923)
Members' Equity, March 5, 2015	48,451	1,912	2,877,701	103,967	—	—	—	—	105,879
Class A Units converted to common units upon limited partnership conversion	(48,451)	(1,912)	—	—	—	—	58,729	1,912	—
Class B Units converted to common units upon limited partnership conversion	—	—	(2,877,701)	(103,967)	—	—	2,877,701	103,967	—
Units tendered by employees for tax withholding	—	—	—	—	—	—	(32,269)	(597)	(597)
Unit-based compensation programs	—	—	—	—	—	—	472,972	2,454	2,454
Private placement of Class A Preferred Units, net of offering costs of $0.8 million	—	—	—	—	10,859,375	16,550	—	—	16,550
Beneficial conversion feature of Class A preferred units	—	—	—	—	—	(863)	—	863	—
Preferred unit paid-in-kind distributions	—	—	—	—	549,756	1,425	—	(1,425)	—
Issuance of common units	—	—	—	—	—	—	6,865	193	193
Common units retired via unit repurchase program	—	—	—	—	—	—	(143,185)	(2,223)	(2,223)
Common units issued for acquisition of properties	—	—	—	—	—	—	105,263	2,000	2,000
Common units received and retired for acquisition of properties	—	—	—	—	—	—	(105,263)	(1,065)	(1,065)
Cash distributions	—	—	—	—	—	—	—	(1,219)	(1,219)
Distributions - Class B preferred units	—	—	—	—	—	—	—	(14,012)	(14,012)
Net loss (March 6th - December 31st)	—	—	—	—	—	—	—	(136,133)	(136,133)
Partners' Capital, December 31, 2015	—	$ —	—	$ —	11,409,131	$ 17,112	3,240,813	$ (45,285)	$ (28,173)

See accompanying notes to consolidated financial statements.

SANCHEZ PRODUCTION PARTNERS LP AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2015 and 2014

1. ORGANIZATION AND BUSINESS

Organization

Sanchez Production Partners LP, a Delaware limited partnership ("SPP", "we", "us", "our" or the "Partnership"), is a publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy production assets. SPP completed its initial public offering on November 20, 2006, as Constellation Energy Partners LLC ("CEP" or the "Company"). We have entered into a shared services agreement (the "Services Agreement") with SP Holdings, LLC (the "Manager"), the sole member of our general partner, pursuant to which Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance and acquisition, disposition and financing services. On March 6, 2015, the Company's unitholders approved the conversion of Sanchez Production Partners LLC to a Delaware limited partnership and the name was changed to Sanchez Production Partners LP. Manager owns the general partner of SPP and all of SPP's incentive distribution rights. Our common units are currently listed on the NYSE MKT under the symbol "SPP."

Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("Sanchez Energy") and entered into a 15-year gathering and processing agreement with Sanchez Energy. We have also commenced a process to sell our oil and gas properties in the Mid-Continent region.

As a result of the acquisition of midstream assets from Sanchez Energy, our historical financial statements (including those in this Form 10-K) will differ substantially from our future financial statements beginning with the quarter ended December 31, 2015 principally because a significant portion of our revenues will come from the long-term, fee-based gathering and processing agreement with Sanchez Energy rather than from oil and natural gas production.

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. We conduct our business activities as two operating segments: the exploration and production of oil and natural gas and the midstream business, which include the Catarina gathering system. 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 condensed consolidated financial statements upon adoption.

In February 2016, the FASB issued Accounting Standards Update ("ASU") No. 2016-02 "Leases (Topic 842)," effective for annual and interim periods for public companies beginning after December 15, 2018, with a modified retrospective approach to be used for implementation. ASU 2016-02 updates the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee's classification of a finance lease. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In November 2015, the FASB issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes", which simplifies the presentation of deferred income taxes. This ASU requires that deferred tax assets and liabilities be classified as non-current in a statement of financial position by jurisdiction rather than separately presented as current and non-current portions. ASU 2015-17 is effective for fiscal years beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for financial statements as of the beginning of an interim or annual reporting period. The Company chose to adopt ASU 2015-17 as of the quarter ended December 31, 2015 on a retrospective basis. Adoption of this guidance did not affect the balance sheet as of December 31, 2014.

In July 2015, the FASB issued ASU No. 2015-11, "Simplifying the Measurement of Inventory," effective for annual and interim periods beginning after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost and net realizable value. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

In April 2015, the FASB issued ASU No. 2015-03, "Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs." This guidance is intended to more closely align the presentation of debt issuance costs under U.S. GAAP with the presentation requirements under International Financial Reporting Standards. Under this new standard, debt issuance costs related to a recognized the debt liability will be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as a separate asset as previously presented. This guidance is effective for fiscal years and interim periods beginning after December 15, 2015. The guidance is to be applied retrospectively to each prior period presented. Early adoption is permitted. The effects of this accounting standard on our financial position, results of operations and cash flows are not expected to be material.

In February 2015, the FASB issued ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis" to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities ("VIEs") or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. These provisions are effective for annual reporting periods beginning after December 15, 2015, and interim periods within those annual periods, with early adoption permitted. These provisions may also be adopted using either a full retrospective or a modified retrospective approach. We are currently assessing the impact that adopting this new accounting guidance will have on our consolidated financial statements and footnote disclosures, but we do not expect the impact to be material.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is not permitted. The guidance may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

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.

Reclassifications

Certain reclassifications have been made to the prior period to conform to the current period presentation. These reclassifications had no effect on total unitholders' equity, net income or net cash provided by or used in operating, investing or financing activities and an immaterial effect on total assets and total liabilities.

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 condensed consolidated financial statements and accompanying footnotes. These estimates and the underlying assumptions affect the amounts of assets and liabilities reported, disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include estimates of our reserves of oil, natural gas and natural gas liquids ("NGLs"); 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.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents. Checks-in-transit are included in accounts payable or as a reduction of cash, depending on the type of bank account the checks were drawn on. There were no checks-in-transit as of December 31, 2015 and 2014.

Restricted Cash

Restricted cash, as of December 31, 2015 and December 31, 2014, of $0.6 million and $1.7 million, respectively, was being held in escrow. The balance as of December 31, 2015 is related to a vendor dispute, and remained in the escrow account until the dispute was resolved in March 2016.

Accounts Receivable, Net

Our accounts receivable are primarily from purchasers of oil and natural gas 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. At December 31, 2015 and December 31, 2014, we had an allowance for doubtful accounts receivable of $0.4 million and $0.2 million, respectively.

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 facility and maintain an investment grade credit rating. Substantially all of our accounts receivables are due from purchasers of oil and natural gas. These sales are generally unsecured and, in some cases, may carry a parent guarantee. As we generally have fewer than 10 large customers for our oil and natural gas sales, 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. Our allowance for doubtful accounts was $0.4 million during 2015 and less than $0.2 million in 2014. We have no off-balance-sheet credit exposure related to our operations or customers.

For the year ended December 31, 2015, three customers accounted for approximately 41%, 33%, and 18% of our sales revenues related to upstream activities, while one customer accounted for 100% of our midstream sales revenues. For the year ended December 31, 2014, five customers accounted for approximately 33%, 30%, 16%, 14% and 7% of our sales revenues.

Derivatives and Hedging Activities

We use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production by reducing our exposure to price fluctuations. Additionally, we use derivative financial instruments in the form of interest rate swaps to mitigate interest rate exposure on our borrowings under our credit facility.

We account for all our open derivatives as mark-to-market activities. All derivative instruments are recorded in the consolidated balance sheets as either an asset or a liability measured at fair value with changes in fair value recognized in earnings. All of our open derivatives are effective as economic hedges of our commodity price or interest rate exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheets under the captions “Risk management assets” and “Risk management liabilities.” We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statements of operations under the caption “Oil sales” or “Natural gas sales” and settled interest rate swaps as “Interest expense.”

Revenue Recognition

Sales are recognized when oil, natural gas and natural gas liquids have been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Oil, natural gas and NGLs are generally sold on a monthly basis. Most of the contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a specific tank battery, gathering or transmission line, quality of oil, natural gas and NGLs, and prevailing supply and demand conditions, so that the price of the oil, natural gas and NGLs fluctuates to remain competitive with other available oil, natural gas and NGLs supplies. As a result, revenues from the sale of oil, natural gas and NGLs will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil, natural gas and NGLs contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. We use the entitlements method when accounting for gas imbalances. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There was only a minimal gas imbalance position on one of our wells in the Mid-continent region at December 31, 2015 and 2014.

Revenues relating to the gathering and transportation sales of oil and natural gas are recognized in the period service is provided. Under these arrangements, 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.

Income Taxes

SPP 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. SPP is subject to franchise tax obligations in Kansas and Texas and state tax obligations in Alabama and Oklahoma. SPP also has informational filing requirements in Georgia, Indiana, Louisiana, Maine, Missouri, New Jersey, New York, Oregon, Pennsylvania, and West Virginia because we have resident unitholders in these states.

Our wholly-owned subsidiary, CEP Services Company, Inc. is a taxable entity. For the years ended December 31, 2015, and 2014, the current and deferred income taxes for the entity were immaterial. The entity has no material deferred tax assets or liabilities.

Earnings per Unit

For the period prior to our conversion, the basic net income (loss) per unit was computed from the two-class method by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocated net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) was allocated to each class in proportion to the class weighted average number of units outstanding for the period, as compared to the weighted average number of units for all classes for the period.

Post conversion, 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.

Environmental Cost

We record environmental liabilities at their undiscounted amounts on our balance sheets in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the federal Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods. At December 31, 2015, we had no environmental liabilities recorded, as no liabilities were deemed necessary.

Unit-Based Compensation

We record compensation expense for all equity grants issued under our Long-Term Incentive Plan based on the fair value at the grant date, recognized over the vesting period.

Other Contingencies

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against the associated reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

3. ACQUISITIONS

Eagle Ford Acquisition

On March 31, 2015, we completed an acquisition of wellbore interests in certain producing oil and natural gas properties in Gonzales County, Texas (the “Eagle Ford properties,” and such acquisition, the “Eagle Ford acquisition”) located in the Eagle Ford Shale in Gonzales County, Texas from Sanchez Energy for a purchase price of $85 million, subject to normal and customary closing adjustments. The effective date of the transaction was January 1, 2015. The acquisition included initial conveyed working interests and net revenue interests for each property which escalate on January 1 for each year from 2016 through 2019, at which point, SPP’s interests in the Eagle Ford properties will stay constant for the remainder of the respective lives of the assets.

The adjusted purchase price of $83.4 million was funded at closing with net proceeds from the private placement of 10,625,000 newly created Class A Preferred Units which were issued for a cash purchase price of $1.60 per unit (pre reverse unit split), resulting in gross proceeds to SPP of $17.0 million, the issuance of 1,052,632 common units (approximately 105,263 common units after adjusting for reverse unit split) to Sanchez Energy, borrowings under the Partnership’s Credit Agreement (as defined in Note 6, “Long-Term Debt”), and available cash.

The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved developed reserves	$	72,889
Facilities		8,002
Fair value of hedges assumed		3,408
Fair value of assets acquired		84,299
Asset retirement obligations		(877)
Ad valorem tax liability		(44)
Fair value of net assets acquired	$	83,378

Western Catarina Midstream Acquisition

On October 14, 2015, we completed an acquisition of midstream assets located in Western Catarina, in the Eagle Ford Shale in South Texas from Sanchez Energy for a purchase price of $345.8 million, subject to normal and customary closing adjustments (the “Western Catarina Midstream acquisition”). The purchase price was funded at closing with net proceeds from the sale of Class B Preferred Units to Stonepeak Catarina Holdings LLC, an affiliate of Stonepeak Infrastructure Partners (“Stonepeak”) and available cash. Additionally, as a result of the Western Catarina Midstream acquisition, we repurchased 105,263 common units previously held by a subsidiary of Sanchez Energy.

The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Fixed assets	$	142,887
Contractual customer relationships		201,888
Purchase of SPP common units from Sanchez Energy		1,065
Fair value of assets acquired	$	345,840

Results of Operations and Pro Forma Information (Unaudited)

The following unaudited pro forma combined financial information for the year ended December 31, 2015 and 2014 reflect the consolidated results of operations of the Partnership as if the Western Catarina Midstream and Eagle Ford acquisitions and related financings had occurred on January 1, 2014. The pro forma information includes adjustments primarily for revenues and expenses from the acquired properties, depreciation, depletion, amortization and accretion, interest expense and debt issuance cost amortization for acquisition debt, amortization of customer contract intangible assets acquired and paid-in-kind units issued in connection with the Class A Preferred Units.

The unaudited pro forma combined financial statements give effect to the events set forth below:

- The Western Catarina Midstream acquisition completed on October 14, 2015.
- Issuance of Class B Preferred Units to finance the Western Catarina Midstream acquisition.
- Repurchase of common units issued to finance a portion of the Eagle Ford acquisition as a part of the Western Catarina Midstream acquisition, and the related effect on net income (loss) per common unit.
- The Eagle Ford acquisition completed on March 31, 2015.
- The increase in borrowings under the Credit Agreement to finance a portion of the Eagle Ford acquisition, and the related adjustments to interest expense.
- Issuance of Class A Preferred Units to finance a portion of the Eagle Ford acquisition, and the related adjustments to preferred paid-in-kind distributions.
- Issuance of common units to finance a portion of the Eagle Ford acquisition and the related effect on net income (loss) per common unit (in thousands, except per unit amounts).

	Year Ended December 31,	
	2015	**2014**
Revenues	$ 105,204	$ 165,022
Net income (loss) attributable to common unitholders	$ (157,161)	$ 8,256
Net income (loss) per unit prior to conversion		
Class A units - Basic and diluted	$ (17.72)	$ 2.16
Class B units - Basic and diluted	$ (14.10)	$ 2.85
Net income (loss) per unit after conversion		
Common units - Basic and diluted	$ (40.32)	$ —

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Partnership would have reported had the Western

Catarina Midstream and Eagle Ford acquisitions and related financings been completed as of the date set forth in this unaudited pro forma combined financial information and should not be taken as indicative of the Partnership’s future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Post-Acquisition Operating Results

The amounts of revenue and excess of revenues over direct operating expenses included in the Partnership’s condensed consolidated statements of operations for the year ended December 31, 2015, for the Eagle Ford acquisition are shown in the table that follows. Direct operating expenses include lease operating expenses and production and ad valorem taxes (in thousands):

	Year Ended December 31, 2015
Revenues	$ 19,357
Excess of revenues over direct operating expenses	$ 14,270

4. FAIR VALUE MEASUREMENTS

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

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

Level 2 – Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. 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). The valuation models used to value derivatives associated with the Partnership's oil and natural gas production are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although third party quotes are utilized to assess the reasonableness of the prices and valuation techniques, there is not sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

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, 2015 (in thousands):

	Fair Value Measurements at December 31, 2015				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2015
Derivative assets	$ —	$ 31,018	$ —	$ —	$ 31,018
Derivative liabilities	—	—	—	—	—
Embedded derivative	—	—	(193,077)		(193,077)
Total net assets	$ —	$ 31,018	$ (193,077)	$ —	$ (162,059)

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, 2014 (in thousands):

	Fair Value Measurements at December 31, 2014				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2014
Derivative assets	$ —	$ 22,919	$ —	$ (90)	$ 22,829
Derivative liabilities	—	(90)	—	90	—
Total net assets	$ —	$ 22,829	$ —	$ —	$ 22,829

As of December 31, 2015 and December 31, 2014, 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 Accounting Standards Codification ("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. The fair values of oil and natural gas properties and asset retirement obligations 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. Our purchase price allocation for the Eagle Ford and Western Catarina Midstream acquisitions are presented in Note 3, ''Acquisitions and Divestitures." Fair value of oil and natural gas properties are presented in Note 7, "Oil and Natural Gas Properties." A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 9, ''Asset Retirement Obligations.''

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 6, "Long-Term Debt."

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate derivatives as of December 31, 2015. 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.

Embedded Derivative – The Partnership entered into a contract for the sale of preferred units in October 2015 which contained provisions that must be bifurcated from the contract and valued as a derivative. The embedded derivative is valued through the use of a Monte Carlo model which utilizes observable inputs, the Partnership's unit prices at various timelines, as well as unobservable inputs related to the weighted probabilities of certain redemption scenarios. We have therefore classified the fair value measurements of our embedded derivative as Level 3 inputs. The Partnership has marked this derivative to market as of December 31, 2015, and incurred approximately $10.0 million loss as a result.

The fair value of the Partnership's embedded derivative classified as Level 3 as of December 31, 2015 was $193.1 million. Changes in the unobservable inputs will impact the fair value measurement of the Partnership's embedded derivative contract.

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

	Significant Unobservable Inputs (Level 3) Year Ended December 31,	
	2015	**2014**
Beginning balance	$ —	$ —
Initial fair value of embedded derivative - bifurcated from mezzanine equity	(183,095)	—
Total (losses) included in earnings	(9,982)	—
Ending balance	$ (193,077)	$ —
(Losses) included in earnings related to derivatives still held as of December 31, 2015, and 2014	$ (9,982)	$ —

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. 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.

As of December 31, 2015, we had the following derivative contracts in place for the periods indicated, all of which are accounted for as mark-to-market activities:

MTM Fixed Price Swaps – NYMEX (Henry Hub)

	For the Year Ended December 31, 2015 (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
2016	1,098,689	$ 4.13	1,048,146	$ 4.14	998,394	$ 4.14	963,327	$ 4.14	4,108,556	$ 4.14
2017	80,563	$ 3.52	75,829	$ 3.52	71,672	$ 3.52	67,984	$ 3.52	296,048	$ 3.52
2018	79,042	$ 3.58	75,404	$ 3.58	72,115	$ 3.58	69,122	$ 3.58	295,683	$ 3.58
2019	73,432	$ 3.62	70,648	$ 3.62	68,088	$ 3.62	65,720	$ 3.62	277,888	$ 3.62
									4,978,175	

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

	For the Year Ended December 31, 2015 (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
2016	121,005	$ 73.53	113,226	$ 73.77	106,483	$ 73.95	100,525	$ 74.10	441,239	$ 73.82
2017	57,953	$ 64.80	54,554	$ 64.80	51,570	$ 64.80	48,926	$ 64.80	213,003	$ 64.80
2018	56,798	$ 65.40	54,197	$ 65.40	51,851	$ 65.40	49,709	$ 65.40	212,555	$ 65.40
2019	52,760	$ 65.65	50,784	$ 65.65	48,960	$ 65.65	47,264	$ 65.65	199,768	$ 65.65
									1,066,565	

The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the year ended December 31, 2015 and the year ended December 31, 2014 (in thousands):

	December 31, 2015	December 31, 2014
Beginning fair value of commodity derivatives	$ 22,829	$ 10,601
Net gains on crude oil derivatives	22,410	13,983
Net gains on natural gas derivatives	6,148	5,871
Net settlements on derivative contracts:		
Crude oil	(13,191)	69
Natural gas	(7,178)	(7,695)
Ending fair value of commodity derivatives	$ 31,018	$ 22,829

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

Derivative Type	Location of Gain in Income	Amount of Gain in Income For the Year Ended December 31, 2015		2014	
Commodity – Mark-to-Market	Oil sales	$	19,147	$	19,854
Commodity – Mark-to-Market	Natural gas sales		6,003		-
		$	25,150	$	19,854

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. As of December 31, 2015 and December 31, 2014, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Hedges Novated in the Eagle Ford Acquisition

As a part of the Eagle Ford acquisition, we received by novation from the seller certain hedges covering approximately 95%, 90%, 85%, 85% and 80% of estimated 2015, 2016, 2017, 2018 and 2019 oil and natural gas production from the acquired assets, respectively. The counterparty for the hedges is a lender in the Partnership's Credit Agreement. The Partnership is responsible for all future periodic settlements of these transactions. As of December 31, 2015, the fair value of the hedges assumed resulted in a $15 million asset in our consolidated balance sheet.

Embedded Derivative

The Partnership entered into a contract for the sale of preferred units in October 2015 which contained provisions that must be bifurcated from the contract and valued as a derivative. The embedded derivative is valued through the use of a Monte Carlo model which utilizes observable inputs, the Partnership's unit prices at various timelines, as well as unobservable inputs related to the weighted probabilities of certain redemption scenarios. The Partnership has marked this derivative to market as of December 31, 2015, and incurred approximately $10.0 million loss as a result.

The following table sets forth a reconciliation of the changes in fair value of the Partnership's embedded derivative for the year ended December 31, 2015, and the year ended December 31, 2014 (in thousands):

	For the Year Ended December 31, 2015		2014	
Beginning fair value of embedded derivative	$	—	$	—
Initial fair value of embedded derivative - bifurcated from mezzanine equity		(183,095)		—
(Losses) on embedded derivative		(9,982)		—
Ending fair value of embedded derivative	$	(193,077)	$	—

6. LONG-TERM DEBT

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto. The credit facility provides a maximum commitment of $500,000,000 and has a maturity date of March 31, 2020. Borrowings under the credit facility 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 facility is limited to the borrowing base for our oil and natural gas properties and our midstream assets. Borrowings under the credit facility are available for direct investment in oil and gas properties, acquisitions, and working capital and general business purposes. The credit facility has a sub-limit of $15,000,000 which may be used for the issuance of letters of credit. The initial borrowing base under the credit facility was $200,000,000. The borrowing base for the credit available for the upstream oil and gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is equal to the rolling four quarter EBITDA of our midstream operations multiplied by 5.0 initially, 4.75 for the second full quarter after the acquisition of the Catarina gathering system and 4.5 thereafter. 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.

At our election, interest for borrowings under the credit facility are determined by reference to (i) the London interbank rate (“LIBOR”) plus an applicable margin between 1.75% and 2.75% per annum based on utilization or (ii) a domestic bank rate (“ABR”) plus an applicable margin between 0.75% and 1.75% per annum based on utilization plus (iii) a commitment fee between 0.375% and 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 facility 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 facility 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 facility Agreement and exercise other rights and remedies.

The credit facility 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 facility, 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 facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At December 31, 2015, we were in compliance with the financial covenants contained in the credit facility. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our credit facility 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 facility, 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, 2015, our unamortized debt issuance costs were $2 million. These costs are amortized to interest expense in our consolidated statement of operations over the life of our Credit Agreement. At December 31, 2014, our unamortized debt issuance costs were $0.7 million.

7. OIL AND NATURAL GAS PROPERTIES

Oil and Natural Gas Properties We follow the successful efforts method of accounting for our oil and natural gas exploration, development and production activities. Leasehold acquisition costs, property acquisition and the costs of development of proved areas are capitalized. 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.

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

Our estimate of proved reserves is based on the quantities of oil, natural gas and natural gas liquids 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, 2015 and 2014 is described in detail in Note 16.

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.

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

	December 31, 2015	December 31, 2014
Oil and natural gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 731,548	$ 649,432
Unproved property	39	1,560
Land	501	501
Total property costs	732,088	651,493
Materials and supplies	1,056	1,056
Total	733,144	652,549
Less: Accumulated depreciation, depletion, amortization and impairments	(652,167)	(517,239)
Oil and natural gas properties and equipment, net	$ 80,977	$ 135,310

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

	December 31, 2015	December 31, 2014
Gathering and transportation assets		
Catarina midstream assets	$ 147,479	$ —
Less: Accumulated depreciation, depletion, amortization	(1,402)	—
Total gathering and transportation assets	$ 146,077	$ —

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. It has been our historical practice to use our year-end reserve report to adjust our depreciation, depletion, and amortization expense for the fourth quarter. Depreciation, depletion, and amortization expense is calculated using year-end reserve reports based on the SEC-required price. As more fully described in Note 16, 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.

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

	Year Ended December 31, 2015	Year Ended December 31, 2014
DD&A of oil and natural gas-related assets	$ 10,330	$ 17,533
DD&A of gathering and transportation related assets	4,206	—
Total DD&A	14,536	17,533
Asset impairments	123,860	5,424
Total	$ 138,396	$ 22,957

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: (ii) future operating and development costs; (iii) future commodity prices; and (iv) 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 the impairment testing exclude derivative instruments.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that we expect to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually.

For the year ended December 31, 2015, we recorded non-cash charges of $123.9 million, to impair the value of our Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties acquired prior to the Eagle Ford acquisition. For the year ended December 31, 2014, we recorded non-cash impairment charge of $5.4 million to impair the value of our oil and natural gas fields in Texas and Louisiana. The carrying values of the impaired proved properties were reduced to fair value of $81 million, estimated using inputs characteristic of a Level 3 fair value measurement.

Asset Retirement Obligation

As described in Note 9, 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, 2015 and 2014, however, we did record $1.9 million for impairments of unproved properties, which is classified as exploration costs on the statement of operations for the year ended December 31, 2015.

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.

8. 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, 2015 and 2014 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 primarily reflects our state tax obligations under the Revised Texas Franchise Tax (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, state and foreign income tax provision (benefit) is summarized below (in thousands):

	For the Year Ended December 31, 2015	2014
Current:		
Federal	$ 2	$ —
State	53	—
Total current	55	—
Deferred:		
Federal	—	—
State	—	—
Total deferred	—	—
Total provision for income taxes	$ 55	$ —

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):

	For the Year Ended December 31, 2015	2014
Pre-Tax Net Book Loss "NBI"	$ (137,001)	$ —
Texas Margin Tax [(a)]	780	—
Return to Accrual	55	—
Valuation Allowance	(780)	—
Provision for income taxes	$ 55	$ —
Effective income tax rate	(0.04)%	- %

(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):

	For the Year Ended December 31, 2015	2014
Deferred tax assets (liabilities):		
Derivative assets	$ (63)	$ —
Depreciable, depletable property, plant and equipment	843	—
Deferred tax assets:	780	—
Valuation allowance	(780)	—
Total Deferred tax assets	$ —	$ —

During November 2015, the FASB issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes", which simplifies the presentation of deferred income taxes. This ASU requires that deferred tax assets and liabilities be classified as non-current in a statement of financial position by jurisdiction rather than separately presented as current and non-current portions. ASU 2015-17 is effective for fiscal years beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for financial statements as of the beginning of an interim or annual reporting period. The Partnership chose to adopt ASU 2015-17 as of the quarter ended December 31, 2015.

As of December 31, 2015 and 2014, the Partnership had no material uncertain tax positions.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities. Subsequently, the ARC is depreciated using a systematic and rational method over the asset's useful life. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other facilities.

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

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

	December 31, 2015	December 31, 2014
Asset retirement obligation, beginning balance	$ 17,031	$ 9,513
Liabilities added from acquisitions	3,634	80
Liabilities added from drilling	—	59
Sold	(58)	—
Revisions to cost estimates	(1,156)	6,780
Settlements	(186)	(5)
Accretion expense	1,099	604
Asset retirement obligation, ending balance	$ 20,364	$ 17,031

Additional retirement obligations increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligation. In 2015 and 2014, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations. During the year ended December 31, 2015, revisions were made to the ARO liability based on recent costs incurred on abandoned wells, which were lower on average than originally projected.

10. COMMITMENTS AND CONTINGENCIES

We did not have any material commitments and contingencies as of December 31, 2015.

11. RELATED PARTY TRANSACTIONS

Sanchez-Related Agreements

We are controlled by our general partner. The sole member of our general partner is Manager, which has no officers. In May 2014, we entered into the Services Agreement with Manager pursuant to which Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. In connection with providing the services under the Services Agreement, Manager receives compensation as discussed above in "Item 13. Certain Relationships." The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless both Manager and the Company provide notice to terminate the agreement. During the year ended December 31, 2015, we paid approximately $9.9 million to Manager pursuant to the Services Agreement. During the year ended December 31, 2014, we paid $6.0 million to Manager under the Services Agreement and issued 5,956 common units to Manager pursuant to the Services Agreement in connection with Manager's election to receive payment of its fee for the quarter ended September 30, 2014 in common units rather than cash, with such issuance being in lieu of paying a fee of $165,582 in cash, or $12.78 per common unit.

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

In May 2014, we entered into the Transition Agreement with SOG and Manager pursuant to which we agreed to make available to Manager and SOG certain of our employees for SOG or Manager to provide services under the Services Agreement and Operating Agreement. No compensation was paid by any party for the provision or use of employees under the Transition Agreement.

On May 8, 2014, the Company and SOG entered into a Contract Operating Agreement, the Company, Manager and SOG entered into a Transition Agreement, and the Company, SOG and certain subsidiaries of the Company entered into the License Agreement. For further discussion of these agreements, refer to our Annual Report on Form 10-K for the year ended December 31, 2014.

In connection with the closing of the Western Catarina Midstream Divestiture, the Partnership entered into a Firm Gathering and Processing Agreement on October 14, 2015 for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas will be dedicated for gathering by Catarina Midstream, LLC ("Catarina Midstream"). In addition, for the first five years of the Gathering Agreement, SN Catarina, LLC will be required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments.

As of December 31, 2015 and December 31, 2014, the Partnership had a net receivable from related parties of $1.5 million and $1.0 million, respectively, which are included in "Accounts receivable – related entities" in the condensed consolidated balance sheets. As of December 31, 2015, the Partnership also had a net payable from related parties of $1.0 million. The net receivables/payable as of December 31, 2015 and December 31, 2014 consist primarily of revenues receivable from oil and natural gas production, offset by costs associated with that production and obligations for general and administrative costs.

Sanchez-Related Transactions

We have entered into several transactions with Sanchez Energy since January 1, 2014. Antonio R. Sanchez, Jr. is a director and Executive Chairman of the Board of Sanchez Energy, and Antonio R. Sanchez, III, is a director and Chief Executive Officer of Sanchez Energy. In addition, Eduardo Sanchez is the 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.

On March 31, 2015, the Partnership and Sanchez Energy entered into a Purchase and Sale Agreement for the Eagle Ford acquisition for total consideration of $85.0 million. After $1.4 million in normal and customary closing adjustments, consideration paid at closing consisted of $81.6 million cash paid by us to Sanchez Energy and 105,263 of our common units issued to Sanchez Energy with an aggregate consideration value of $2,000,000. In connection with the purchase agreement, we entered into a registration rights agreement with Sanchez Energy pursuant to which we granted certain registration rights related to the common unit consideration received. As of December 31, 2015, there were no common units held by Sanchez Energy or related subsidiaries thereof. All 105,263 common units issued as consideration for the Eagle Ford acquisition were repurchased in connection with the Western Catarina Midstream acquisition in October 2015. See further discussion of the transaction in Note 3, "Acquisitions."

In October 2015, the Partnership and Sanchez Energy consummated the Western Catarina Midstream acquisition for total consideration of approximately $345.8 million in cash, subject to closing and post-closing adjustments. Concurrently with the signing of the Western Catarina Midstream acquisition purchase and sale agreement, we entered into a 15-year gas gathering and processing agreement with Sanchez Energy. For the year ended December 31, 2015, Sanchez Energy paid us approximately $7.5 million pursuant to the terms of the gathering and processing agreement. See further discussion of the transaction in Note 3, "Acquisitions."

12. UNIT-BASED COMPENSATION

Prior to our conversion to a Delaware limited partnership on March 6, 2015, we granted restricted common unit awards to certain employees in Texas under the 2009 Omnibus Incentive Compensation Plan (the "Omnibus Plan"). The Omnibus Plan provided for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Additionally, prior to March 6, 2015, we granted restricted common unit awards to certain field employees in Kansas and Oklahoma and to certain employees in Texas under our previous Long-Term Incentive Plan (the "Previous LTIP").

After the conversion to a limited partnership, both the Omnibus Plan and the Previous LTIP had no outstanding units remaining. Effective March 6, 2015, the Omnibus Plan was amended and restated and renamed the Sanchez Production Partners LP Long-Term Incentive Plan (the "LTIP") and the Previous LTIP was merged into the LTIP. Restricted unit activity under the Omnibus Plan, the Previous LTIP, and the LTIP during the period, after adjusting for the reverse split, is presented in the following table:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2013	38,033	$ 32.42
Granted[1]	44,968	24.40
Vested[1]	(55,034)	27.48
Returned/Cancelled[1]	(17,884)	28.16
Outstanding at December 31, 2014	10,083	31.10
Granted[1]	472,972	18.68
Vested[1]	(87,872)	14.89
Returned/Cancelled[1]	(33,826)	17.33
Outstanding at December 31, 2015	361,357	$ 14.18

(1) Values herein presented as if Omnibus Plan and Previous LTIP had merged as of the earliest date presented.

During the year ended December 31, 2015, the Partnership issued 346,925 restricted common units (34,693 restricted common units after adjusting for reverse unit split) pursuant to the LTIP to the directors of the Partnership's general partner that vested immediately on the date of the grant. The unit based compensation expense for the awards were based on their grant date fair values. In March 2015, officers were granted a total of 1,025,641 restricted common units (102,564 restricted common units after adjusting for the reverse unit split) that were due upon request, of which 769,231 restricted common units (76,923 restricted common units after adjusting for reverse unit split) were vested and delivered at the request of the officers, net of 322,692 restricted common units (32,269 restricted common units after adjusting for reverse unit split) that were returned to the plan for settlement of taxes associated with the vesting. Furthermore, on December 1, 2015 the board of directors approved the grant of 335,715 restricted units pursuant to the LTIP to employees, service providers, and executive officers which are set to vest pro-rata over a three-year period.

13. DISTRIBUTIONS TO UNITHOLDERS

From the second quarter of 2009 through the second quarter of 2015, we did not pay distributions on our common units. Starting in the third quarter of 2015, the board of directors of our general partner declared distributions of Class A Preferred Units on August 10, 2015 and November 10, 2015 to holders as of August 14, 2015 and November 16, 2015, respectively. A total of 549,756 paid-in-kind units were distributed for the year ended December 31, 2015. On November 30, 2015, we paid a cash distribution with respect to the quarter ended September 30, 2015 in the amount of $0.400 per common unit. On February 9, 2016, we announced that the board of directors of our general partner approved a cash distribution of $0.406 per common unit for the fourth quarter of 2015. The Partnership also declared a fourth quarter 2015 paid-in-kind distribution of 2.5% on its Class A preferred units and a fourth quarter prorated cash distribution of $0.3815 on its Class B preferred units. The distributions were paid on February 29, 2016 to unitholders of record on February 19, 2016.

14. MEMBERS' EQUITY/PARTNERS' CAPITAL

Outstanding Units

As of December 31, 2015, we had 11,409,131 Class A Preferred Units outstanding, 19,444,445 Class B Preferred Units outstanding, and 3,240,812 common units outstanding, which included 25,641 unvested restricted common units issued under the LTIP.

Conversion

The board of managers of Sanchez Production Partners LLC ("SPP LLC") approved a Plan of Conversion (the "Conversion") providing for the conversion of the company from a limited liability company formed under the laws of the State of Delaware into a limited partnership formed under the laws of the State of Delaware. This plan was approved by the vote of the unitholders of SPP LLC on March 6, 2015. After the Conversion, all of the rights, privileges and obligations of the Company prior to the Conversion were transferred and are now held by the Partnership. The Conversion converted each outstanding common unit of the Company into one common unit of the Partnership. The outstanding Class A units of the Company were converted into common units of the Partnership in a number equal to 2% of the Partnership's common units outstanding immediately after the Conversion (after taking into account the conversion of such Class A units), and the outstanding Class Z unit of the Company was cancelled. In addition, a non-economic general partner interest in the Partnership was issued to our general partner, and the incentive distribution rights of the Partnership were issued to Manager.

Common Unit Issuances

In April 2015, we entered into an at-the-market sales agreement with MLV & Co. LLC to sell from time to time up to $100 million of common units, with any proceeds from such sales to be used for general limited partnership purposes. As of December 31, 2015, we had sold 68,000 common units (6,800 common units after adjusting for reverse unit split) for total net proceeds of less than $0.2 million. During 2015, we paid de minimis commissions to the sales agent in connection with the at-the-market facility.

On August 3, 2015, the Partnership effected a 1-for-10 reverse split on its common units, pursuant to which common unitholders received one common unit for every ten common units held at the close of trading on August 3, 2015. All fractional units created by the reverse split were rounded to the nearest whole unit. Each unitholder received at least one unit. Post-split units of the Partnership began trading on August 4, 2015. Immediately prior to the reverse unit split, there were 31,495,506 common units of the Partnership issued and outstanding, with a per unit closing trading price on the NYSE MKT on August 3, 2015 of $1.55. Immediately after the reverse unit split, the number of issued and outstanding common units of the Partnership decreased to 3,149,551, not inclusive of shares required by DTCC due to the rounding up of fractional shares at the beneficial level, and the per unit opening trading price on the NYSE MKT was $15.50.

Preferred Unit Issuance

Class A Preferred Unit Offerings: On March 31, 2015, the Partnership entered into a Class A Preferred Unit Purchase Agreement (the "Preferred Unit Purchase Agreement") with the purchasers named on Schedule A thereto (collectively, the "Purchasers"), pursuant to which the Partnership sold, and the Purchasers purchased, 10,625,000 of the Partnership's newly created Class A Preferred Units (the "Class A Preferred Units") in a privately negotiated transaction (the "Private Placement") for an aggregate cash purchase price of $1.60 per Class A Preferred Unit resulting in gross proceeds to the Partnership of $17 million. The Partnership used the net proceeds of $17.0 from this transaction, together with common units issued to Sanchez Energy, borrowings under the Credit Agreement, and available cash on hand, to pay the consideration in the Eagle Ford acquisition.

Additionally, on April 15, 2015, the Partnership entered into a Class A Preferred Unit Purchase Agreement (the "April Preferred Unit Purchase Agreement") with the purchasers named on Schedule A thereto (collectively, the "April

Purchasers"), pursuant to which the Partnership sold, and the April Purchasers purchased, 234,375 of the Partnership's Class A Preferred Units in a privately negotiated transaction for an aggregate cash purchase price of $1.60 per Class A Preferred Unit resulting in gross and net proceeds to the Partnership of $375,000. The Partnership used the proceeds for general working capital purposes.

Commencing with the three months ended June 30, 2015 and through the date on which the Class A Preferred Units are converted into common units, the holders of the Class A Preferred Units shall be entitled to receive distributions. For the three months ended June 30, 2015, through and including the three months ending June 30, 2016, the distributions will be paid in kind with additional Class A Preferred Units; thereafter, distributions will be paid in-kind or in cash at the discretion of the board of directors of our general partner. For the first year after the issuance date, the distribution rate will be 10% per annum, or 2.5% per quarter; for the second year after the issuance date, the distribution rate will be 11.5% per annum, or 2.875% per quarter; and thereafter, the distribution rate will be 12.5% per annum, or 3.125% per quarter. Distributions will be made on or about the last day of each of February, May, August and November following the end of each quarter commencing with the three months ended June 30, 2015.

On August 10, 2015, the board of directors of our general partner declared a distribution to holders of Class A Preferred Units as of August 14, 2015 to be paid in kind for the three months ended June 30, 2015. This distribution to the holders was made on August 31, 2015. Further, o n November 10, 2015, the board of directors of our general partner declared a distribution to holders of Class A Preferred Units as of November 16, 2015 to be paid in kind and distributed to the holders on November 30, 2015.

Class B Preferred Unit Offering: On October 14, 2015, pursuant to that certain Class B Preferred Unit Purchase Agreement dated September 25, 2015 (the "Preferred Unit Purchase Agreement") between the Partnership and Stonepeak Catarina Holdings LLC (the "Purchaser"), the Partnership sold and the Purchaser purchased 19,444,445 of the Partnership's newly created Class B Preferred Units (the "Class B Preferred Units") in a privately negotiated transaction (the "Private Placement") for an aggregate cash purchase price of $18.00 per Class B Preferred Unit, which resulted in gross proceeds to the Partnership of $350,000,010. The Partnership used the net proceeds to pay a portion of the consideration under the Purchase Agreement, along with the payment to the Purchaser of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

Under the terms of the Amended Partnership Agreement, commencing with the quarter ended on December 31, 2015, the Class B Preferred Units will receive a quarterly distribution of, 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 paid-in-kind units (4.0% per annum). In the event the Partnership does not raise at least $75,000,000 through the issuance of additional common units prior to September 30, 2016 (with the conversion of the Class A Preferred Units of the Partnership counting toward such amount) or if any Class A Preferred Units remain outstanding after March 31, 2016, the cash portion of the distribution rate will increase by 4.0% per annum until consummation of such issuance or conversion, as applicable. 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.

The holders of Class B Preferred Units have the right at any time to request conversion in whole or in part of their Class B Preferred Units at the Conversion Rate, subject to the requirement to convert a minimum of $17,500,000 of Class B Preferred Units. The "Conversion Rate" is equal to the quotient of (i) the aggregate purchase price for the Class B Preferred Units plus accrued and unpaid distributions thereon, divided by (ii) the lesser of (a) the purchase price for the Class B Preferred Units and (b) the volume weighted average price for which common units are issued by the Partnership during the period beginning on the private placement closing date and ending on the date on which the Partnership has issued common units (other than issuances pursuant to the LTIP) in exchange for cash in an aggregate amount equal to at least $75 million.

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

	For the Year Ended December 31,	
	2015	2014
Private placement of Class B Preferred Units	$ 350,000	$ —
Less: discount	(191,901)	—
Less: amortization of discount	6,594	—
Less: distributions	7,418	—
Total mezzanine equity	$ 172,111	$ —

Earnings per Unit

For the period prior to our conversion, the basic net income (loss) per unit was computed from the two-class method by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocated net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) was allocated to each class in proportion to the class weighted average number of units outstanding for the period, as compared to the weighted average number of units for all classes for the period.

Post conversion, 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.

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

The following table presents the weighted average basic and diluted units outstanding for the periods indicated:

	January 1 - March 6 2015	March 6 - December 31 2015	Year Ended December 31, 2014
Class A units - Basic	484,505	—	763,261
Class B Common units - Basic	28,791,626	—	28,431,586
Common units - Basic	—	30,715,874	—
Weighted Common Units prior to reverse split - Basic	29,276,131	30,715,874	29,194,847
Adjustment for reverse split	(26,348,518)	(27,644,287)	(26,275,362)
Weighted Common Units after reverse split - Basic	2,927,613	3,071,587	2,919,485
Class A units - Diluted	484,505	—	763,261
Class B Common units - Diluted	28,791,626	—	28,532,411
Common units - Diluted	—	30,715,874	—
Weighted Common Units prior to reverse split - Diluted	29,276,131	30,715,874	29,295,672
Adjustment for reverse split	(26,348,518)	(27,644,287)	(26,366,105)
Weighted Common Units after reverse split - Diluted	2,927,613	3,071,587	2,929,567

At December 31, 2015, we had 361,356 common units that were restricted unvested common units granted and outstanding. No losses were allocated to participating restricted unvested units because such securities do not have a contractual obligation to share in the Partnership's losses. At December 31, 2014, we had 100,825 Class B common units that were restricted unvested common units granted and outstanding. These units were included in the diluted weighted average common units outstanding number since we recognized net income for the period.

The following table presents our basic and diluted loss per unit for the period from January 1, 2015 to March 6, 2015 (the date of conversion to a limited partnership) (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Assumed net loss to be allocated January 1 - March 6	$ (923)	$ (18)	$ (905)
Basic and diluted loss per unit prior to reverse split		$ (0.04)	$ (0.03)
Basic and diluted loss per unit after reverse split		$ (0.38)	$ (0.31)

The following table presents our basic and diluted loss per unit for the period from March 6, 2015 through December 31, 2015 (the period after conversion to a limited partnership) (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss attributable to common unitholders to be allocated March 6 - December 31	$ (153,895)	$ (153,895)
Basic and diluted loss per unit prior to reverse split		$ (5.01)
Basic and diluted loss per unit after reverse split		$ (50.10)

Net loss per unit increased significantly for the period from March 6, 2015 through December 31, 2015 as compared to the period from January 1, 2015 through March 5, 2015 as it included non-cash impairment charges of $123.8 million. There was no impairment charge recorded for the period from January 1, 2015 through March 5, 2015.

The following table presents our basic and diluted income per unit for the year end December 31, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Assumed net income to be allocated	$ 9,503	$ 190	$ 9,313
Basic and diluted income per unit prior to reverse split		$ 0.25	$ 0.33
Basic and diluted income per unit after reverse split		$ 2.50	$ 3.30

15. REPORTING SEGMENTS

Exploration and Production and Midstream best define the operating segments of the businesses that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The Exploration and Production segment operates to explore for and produce crude oil and natural gas. The Midstream segment operates the gathering, processing and transportation of crude oil, NGLs 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 to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available. Operating segments are evaluated for their contribution to the Partnership's consolidated results based on operating income, which is defined as segment operating revenues less expenses.

The following tables set forth our segment information for the periods indicated (in thousands):

	Year Ended December 31, 2015		
	Exploration & Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 19,809	$ —	$ 19,809
Oil sales	35,297	—	35,297
Natural gas liquids sales	1,597	—	1,597
Gathering and transportation sales	—	11,725	11,725
Total operating revenues	56,703	11,725	68,428
Operating expenses:			
Lease operating expenses	19,890	98	19,988
Transportation operating expenses	—	2,176	2,176
Cost of sales	595	—	595
Production taxes	1,792	—	1,792
General and administrative	26,109	—	26,109
Exploration costs	1,866	—	1,866
Gain on sale of assets	(111)	—	(111)
Depreciation, depletion and amortization	10,330	4,206	14,536
Asset impairments	123,860	—	123,860
Accretion expense	1,048	51	1,099
Total operating expenses	185,379	6,531	191,910
Operating income (loss)	$ (128,676)	$ 5,194	$ (123,482)

	Year Ended December 31, 2014		
	Exploration & Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 34,458	$ —	$ 34,458
Oil sales	40,337	—	40,337
Natural gas liquids sales	2,477	—	2,477
Gathering and transportation sales	—	—	—
Total operating revenues	77,272	—	77,272
Operating expenses:			
Lease operating expenses	21,012	—	21,012
Cost of sales	1,487	—	1,487
Production taxes	3,200	—	3,200
General and administrative	16,499	—	16,499
Loss on sale of assets	223	—	223
Depreciation, depletion and amortization	17,533	—	17,533
Asset impairments	5,424	—	5,424
Accretion expense	604	—	604
Total operating expenses	65,982	—	65,982
Operating income	$ 11,290	$ —	$ 11,290

The following table summarizes the total assets by operating segment for the years ended December 31, 2015 and 2014 (in thousands):

	December 31,	
Segment Assets	2015	2014
Exploration & Production	$ 120,174	$ 173,247
Midstream	353,217	—
Total assets	$ 473,391	$ 173,247

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

	Year Ended December 31,	
	2015	2014
Exploration & Production		
Customer A	33 %	33 %
Customer B	41	30
Customer C	1	16
Customer D	18	14
All Others	7	7
Total	100 %	100 %
Midstream		
Customer E	100 %	— %
Total	100 %	— %

16. 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 capitalized costs for the years ended December 31, 2015 and 2014 (in thousands):

	December 31,	
	2015	2014
Capitalized costs at the end of the period:[a]		
Oil and natural gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 731,548	$ 649,432
Unproved property	39	1,560
Land	501	501
Total property costs	732,088	651,493
Materials and supplies	1,056	1,056
Total	733,144	652,549
Less: Accumulated depreciation, depletion, amortization and impairments	(652,167)	(517,239)
Oil and natural gas properties and equipment, net	$ 80,977	$ 135,310

(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, 2015 and 2014 (in thousands):

	For the Year Ended December 31,	
	2015	2014
Costs incurred for the period:		
Acquisition of properties		
Proved	$ 81,378	$ 1,239
Unproved	—	112
Development costs	468	5,865
Oil and natural gas properties and equipment, net	$ 81,846	$ 7,216

The development costs for the years ended December 31, 2015 and 2014 primarily represent costs to develop our proved undeveloped reserves. The properties acquired in 2015 and 2014 were in Texas and Louisiana.

We had no exploration and dry hole costs in 2015 and 2014, with the exception of impairments related to unproved properties which were recorded as exploration costs.

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 operations are oil and natural gas producing activities located in the United States.

Net Proved Oil, Natural Gas and Natural Gas Liquids Reserves

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, 2013	15,209	2,072	12,994	143
Extensions and discoveries	509	416	93	—
Puchase of reserves in place	72	72	—	—
Revisions of previous estimates	2,361	(590)	3,008	(57)
Production	(1,524)	(308)	(1,188)	(28)
December 31, 2014	16,627	1,662	14,907	58
Extensions and discoveries	3	3	—	—
Puchase of reserves in place	5,124	3,516	799	809
Revisions of previous estimates	(9,038)	(1,754)	(7,175)	(109)
Production	(1,074)	(268)	(795)	(11)
December 31, 2015	11,642	3,159	7,736	747
Proved developed reserves:				
December 31, 2014	12,439	1,523	10,858	58
December 31, 2015	11,523	3,071	7,705	747
Proved undeveloped reserves:				
December 31, 2014	4,188	139	4,049	—
December 31, 2015	119	88	31	—

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 December 31, 2015 and 2014, proved reserve estimates were 11.6 MMBoe and 16.6 MMBoe, respectively. For 2015, NSAI and Ryder Scott, independent petroleum engineering firms, prepared the estimates of our proved reserves which were used to prepare our financial statements. For 2014, NSAI prepared the estimates of our proved reserves which were used to prepare our financial statements.

Our 2015 estimates of total proved reserves decreased 5.0 MMBoe from 2014 due to a 4.0 MMBoe decrease in undeveloped gas reserves. The lower volumes were due to a higher gas price. Our reserves are 66% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. For the proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report: $50.28 per barrel for oil, $19.90 per barrel for NGLs and $2.58 per Mcf for natural gas. Proved developed producing reserves were lower due to natural production decline.

Our 2014 estimates of total proved reserves increased 1.4 MMBoe from 2013 due to a 2.2 MMBoe increase in undeveloped gas reserves in the Cherokee Basin. The higher volumes were due to a higher gas price. Our reserves are 90% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. For the proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report: $93.95 per barrel for oil, $35.11 per barrel for NGLs and $4.09 per Mcf for natural gas. Proved developed producing reserves were lower due to natural production decline.

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

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

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

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

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

	For the Year Ended December 31,	
	2015	**2014**
Future cash inflows	$ 289,767	$ 532,152
Future production costs	(165,861)	(260,909)
Future estimated development costs	(19,026)	(57,741)
Future net cash flows	104,880	213,502
10% annual discount for estimated timing of cash flows	(37,028)	(93,969)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 67,852	$ 119,533

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

	For the Year Ended December 31, 2015	2014
Beginning of the period	$ 119,533	$ 143,714
Sales and transfers of oil and natural gas, net of production costs	(30,748)	(38,817)
Net changes in prices and production costs related to future production	(125,979)	(18,410)
Development costs incurred during the period	5,016	18,075
Changes in extensions and discoveries	178	24,611
Revisions of previous quantity estimates	(11,299)	(22,034)
Purchases and sales of reserves in place	109,181	1,918
Accretion discount	11,953	14,371
Other	(9,983)	(3,895)
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 67,852	$ 119,533

17. SUBSEQUENT EVENTS

On February 9, 2016, the board of directors of the general partner of the Partnership declared a fourth quarter 2015 cash distribution on its common units of $0.4060 per unit ($1.6240 per unit annualized) payable on February 29, 2016 to holders of record on February 19, 2016. The Partnership also declared a fourth quarter 2015 paid-in-kind distribution of 2.5% on its Class A preferred units and a fourth quarter prorated cash distribution of $0.3815 on its Class B preferred units, each payable on February 29, 2016 to holders of record on February 19, 2016.

SIGNATURES

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

Sanchez Production Partners LP

By: Sanchez Production Partners GP LLC,
its general partner

Date: March 30, 2016

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

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 30, 2016
/S/ Gerald F. Willinger **Gerald F. Willinger**	Director; Chief Executive Officer (Principal Executive Officer)	March 30, 2016
/s/ Charles C. Ward **Charles C. Ward**	Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)	March 30, 2016
/s/ Patricio D. Sanchez **Patricio D. Sanchez**	Director; Chief Operating Officer (Principal Operating Officer)	March 30, 2016
/s/ Kirsten A. Hink **Kirsten A. Hink**	Chief Accounting Officer (Principal Accounting Officer)	March 30, 2016
/s/ Alan S. Bigman **Alan S. Bigman**	Director	March 30, 2016
/s/ Jack Howell **Jack Howell**	Director	March 30, 2016
/s/ Richard S. Langdon **Richard S. Langdon**	Director	March 30, 2016
/s/ G. M. Byrd Larberg **G. M. Byrd Larberg**	Director	March 30, 2016
/s/ Eduardo. A Sanchez **Eduardo A Sanchez**	Director	March 30, 2016
/s/ Luke R Tayler **Luke R. Taylor**	Director	March 30, 2016

EXHIBIT INDEX

Exhibit Number	Description
1.1	At Market Issuance Sales Agreement, dated as of April 17, 2015, between Sanchez Production Partners LP and MLV & Co. LLC (incorporated herein by reference to Exhibit 1.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 17, 2015, File No. 001-33147).
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
2.4	Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson's Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on September 29, 2006, File No. 333-134995).
2.7	Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	Membership Interest Purchase and Sale Agreement, dated February 1, 2013 between Constellation Energy Partners LLC and Constellation Commodities Upstream LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on February 4, 2013, File No. 001-33147).

2.10	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).
2.11	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).
2.12	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).
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	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).
3.4	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).
3.5	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 filed by Sanchez Production Partners LP on August 14, 2015, File No. 001-33147).
3.6	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).
10.1	Class A Preferred Unit Purchase Agreement, dated as of March 31, 2015, between Sanchez Production Partners LP and the purchasers 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 April 1, 2015, File No. 001-33147).
10.2	Class A Preferred Unit Purchase Agreement, dated as of April 15, 2015, between Sanchez Production Partners LP and the purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 15, 2015, File No. 001-33147).

10.3	Class B Preferred Unit Purchase Agreement, dated as of September 25, 2015, between Sanchez Production Partners LP and the purchaser named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on September 29, 2015, File No. 001-33147).
10.4	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).
10.5	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).
10.6	Joinder, Assignment and Second Amendment to Third Amended and Restated Credit Agreement, dated as of October 14, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
10.7	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).
10.8	Exploration and Development Agreement, dated July 25, 2005, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.9	Substituted and Replaced First Amendment to the Exploration and Development Agreement, dated October 18, 2006, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.10	Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.11	Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.12	First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).

10.13	Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson's Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.14	Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson's Bend Operating II, LLC, Robinson's Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
10.15+	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.16+	Mutual Termination, Waiver and Release, dated January 22, 2016, between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on January 27, 2016, File No. 001-33147).
*10.17+	Summary Compensation of Executive Officers of Sanchez Production Partners GP LLC.
*10.18+	Summary Compensation of Directors of Sanchez Production Partners GP LLC.
10.19	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-K filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).
10.20	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).
10.21	Geophysical Seismic Data Use License Agreement, dated May 8, 2014, between Constellation Energy Partners, LLC, certain subsidiaries thereof, and Sanchez Oil & Gas Corporation (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 8, 2014, File No. 001-33147).
10.22	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-K filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).
10.23	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).
10.24+	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).

10.25+	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).
10.26+	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).
*21.1	List of subsidiaries of Sanchez Production Partners LLC.
*23.1	Consent of KPMG LLP.
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*23.3	Consent of Ryder Scott Co. LP
*31.1	Certification of Chief Executive Officer of Sanchez Production 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 Production Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer of Sanchez Production Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer and Secretary of Sanchez Production 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 Netherland, Sewell & Associates, Inc.
*99.2	Report of Ryder Scott Co. LP
*101.INS	—XRBL Instance Document
*101.SCH	—XRBL Schema Document
*101.CAL	—XRBL Calculation Linkbase Document
*101.LAB	—XRBL Label Linkbase Document
*101.PRE	—XRBL Presentation Linkbase Document
*101.DEF	—XRBL Definition Linkbase Document

* Filed herewith

\+ Management contract or compensatory plan or arrangement.

Summary of Executive Officers Compensation

Base Salary

The following table sets forth the base salary for each named executive officer of Sanchez Production Partners GP LLC, the general partner of Sanchez Production Partners LP (the "Partnership"). Each person is an employee of Sanchez Oil & Gas Corporation ("SOG") and provides services to the Partnership, with the amounts listed being the portion of the salary allocated to the Partnership, effective as of January 1, 2016.

Sanchez Production Partners LP, Officer	Base Salary
Gerald F. Willinger *Chief Executive Officer*	$600,000
Charles C. Ward *Chief Financial Officer, Treasurer, and Secretary*	$275,000
Patricio D. Sanchez *Chief Operating Officer*	$400,000
Kirsten Hink *Chief Accounting Officer*	$46,750

Other Benefits

SOG does not maintain a defined benefit pension plan for its employees because it believes that such plans primarily reward longevity rather than performance. SOG provides a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. In its discretion, SOG and/or the board of directors of the Partnership's general partner may award the named executive officers cash bonuses and/or equity compensation.

Exhibit 10.18

Annex A

*Board Compensation for Directors**

Type of Compensation	Amount
Board Cash Retainer	$10,000, payable quarterly on the last day of each fiscal quarter, commencing September 30, 2015+
Equity Grant	$100,000 (issued March 31 of each year based on the Partnership's Common Unit closing price on the NYSE MKT on such date (or the next trading day if such date is not a trading day)); fully vested upon issuance; any person appointed to the Board shall be issued equity on a pro rata basis from the date of appointment through the following March 31 (with the number of Common Units based on the closing price on the NYSE MKT on the date of appointment (or the next trading day if such date is not a trading day))
Board Meeting Fees	$1,500 for each meeting attended
Committee Meeting Fees	$1,000 for each substantive meeting of the Audit Committee attended
	$3,500 for each substantive meeting of the Conflicts Committee attended
Committee Chair Retainer	$3,500 for Audit Committee Chair, payable quarterly on the last day of each fiscal quarter+
	$2,500 for Conflicts Committee Chair, payable quarterly on the last day of each fiscal quarter+

---

* Includes all persons serving as directors.

\+ For any person who ceases to serve during the fiscal quarter prior to such payment date, such person shall receive a pro rata amount for the portion of the fiscal quarter so served.

Exhibit 21.1

List of Subsidiaries of Sanchez Production Partners LP

Name	Jurisdiction of Organization
CEP Mid-Continent LLC	Delaware
CEP Services Company, Inc.	Delaware
Northeast Shelf Energy, L.L.C.	Oklahoma
Mid-Continent Oilfield Supply, L.L.C.	Oklahoma
SEP Holdings IV, LLC	Delaware
Catarina Midstream, LLC	Delaware

* The names of certain indirectly owned subsidiaries have been omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary pursuant to Rule 1-02(W) of Regulation S-X.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

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

We consent to the incorporation by reference in the registration statements on Form S-4 (Nos. 333-198440 and 333-202526), Form S-8 (No. 333-202578), Form S-3 (No. 333-204277) and Form S-3 (No. 333-202575) of Sanchez Production Partners LP (formerly Sanchez Production Partners LLC) of our report dated March 30, 2016, with respect to the consolidated balance sheets of Sanchez Production Partners LP as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in members' equity/partners' capital, and cash flows for years then ended, which report appears in the December 31, 2015 Annual Report on Form 10-K of Sanchez Production Partners LP.

/s/ KPMG LLP

Houston, Texas
March 30, 2016

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm in the Annual Report on Form 10-K for Sanchez Production Partners LP (the "Form 10-K") and to the inclusion of our report, dated February 11, 2016 with respect to the estimates of reserves and future net revenues as of December 31, 2015, in the Form 10-K and/or as an exhibit to the Form 10-K.

We hereby consent to the incorporation by reference in the Registration Statement on Form S-4 (Nos. 333-198440 and 333-202526), Form S-8 (No. 333-202578), Form S-3 (No. 333-204277) and Form S-3 (No. 333-202575) of such information.

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Danny D. Simmons

By: ______________________________

Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 30, 2016

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm in the Annual Report on Form 10-K for Sanchez Production Partners LP (the "Form 10-K") and to the inclusion of our report, dated January 21, 2016 with respect to the estimates of reserves and future net revenues as of December 31, 2015, in the Form 10-K and/or as an exhibit to the Form 10-K.

We hereby consent to the incorporation by reference in the Registration Statement on Form S-4 (Nos. 333-198440 and 333-202526), Form S-8 (No. 333-202578), Form S-3 (No. 333-204277) and Form S-3 (No. 333-202575) of such information.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 30, 2016

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

Exhibit 31.1

CERTIFICATION

I, Gerald F. Willinger, certify that:

1. I have reviewed this annual report on Form 10-K of Sanchez Production Partners LP;

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

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

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

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

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

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

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

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

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

/s/ GERALD F. WILLINGER
Gerald F. Willinger
Chief Executive Officer

Date: March 30, 2016

Exhibit 31.2

CERTIFICATION

I, Charles C. Ward, certify that:

1. I have reviewed this annual report on Form 10-K of Sanchez Production Partners LP;

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

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

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

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

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

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

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

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

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

/s/ CHARLES C. WARD
Charles C. Ward
Chief Financial Officer, Secretary and Treasurer

Date: March 30, 2016

Exhibit 32.1

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

In connection with the accompanying annual report of Sanchez Production Partners LP (the "Company") on Form 10-K for the year ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Gerald F. Willinger, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ GERALD F. WILLINGER
Gerald F. Willinger
Chief Executive Officer

Date: March 30, 2016

Exhibit 32.2

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

In connection with the accompanying annual report of Sanchez Production Partners LP (the "Company") on Form 10-K for the year ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charles C. Ward, Chief Financial Officer, Secretary and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ CHARLES C. WARD
Charles C. Ward
Chief Financial Officer, Secretary and Treasurer

Date: March 30, 2016

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 99.1

Mr. Richard M. Miller
Sanchez Production Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

Dear Mr. Miller:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2015, to the Sanchez Production Partners LP (Sanchez) interest in certain oil and gas properties located in Kansas and Oklahoma. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 57 percent of all proved reserves owned by Sanchez. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Sanchez's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Sanchez interest in these properties, as of December 31, 2015, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	364.2	11,388.5	13,162.8	11,589.4
Proved Developed Non-Producing	0.0	25,576.3	12,583.4	4,401.9
Proved Undeveloped	87.9	184.7	2,553.6	1,739.5
Total Proved	452.1	37,149.5	28,299.9	17,730.8

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Sanchez's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Sanchez's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2015. For oil volumes, the average West Texas Intermediate spot price of $50.28 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.587 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $49.48 per barrel of oil and $2.666 per MCF of gas.

Operating costs used in this report are based on operating expense records of Sanchez. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Sanchez are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Sanchez and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Sanchez's estimates of the costs to abandon the wells and production facilities; these estimates do not include any salvage value for the lease and well equipment. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Sanchez interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Sanchez receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Sanchez, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Sanchez, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. David E. Nice, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 13 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

By: /s/ David E. Nice
David E. Nice, P.G. 346
Vice President

Date Signed: February 11, 2016

Date Signed: February 11, 2016

WKB:TML

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence

exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- Ÿ The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
- Ÿ The company's historical record at completing development of comparable long-term projects;
- Ÿ The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
- Ÿ The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
- Ÿ The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.2

SANCHEZ PRODUCTION PARTNERS LP

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2015

\s\ Don P. Griffin

Don P. Griffin, P.E.
TBPE License No. 64150
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 21, 2016

Sanchez Production Partners LP
1000 Main, Suite 3000
Houston, Texas 77002

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Sanchez Production Partners LP (Sanchez) as of December 31, 2015. The subject properties are located in the Palmetto area of the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009, in the Federal Register (SEC regulations). Our third party study, completed on January 15, 2016, and presented herein, was prepared for public disclosure by Sanchez in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon and gas reserves of Sanchez as of December 31, 2015.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2015, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
SANCHEZ PRODUCTION PARTNERS LP
As of December 31, 2015

	Proved		
	Developed		Total
	Producing	Non-Producing	Proved
Net Remaining Reserves			
Oil/Condensate – MBarrels	2,632	76	2,708
Plant Products – MBarrels	703	44	747
Gas – MMCF	8,376	889	9,265
MBOE	4,731	268	4,999
Income Data (M$)			
Future Gross Revenue	$ 151,185	$ 5,983	$ 157,168
Deductions	77,698	2,890	80,588
Future Net Income (FNI)	$ 73,487	$ 3,093	$ 76,580
Discounted FNI @ 10%	$ 49,023	$ 1,098	$ 50,121

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the state of Texas. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousands of barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Sanchez. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 85.4 percent and gas reserves account for the remaining 14.6 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discounted Future Net Income (M$)

	As of December 31, 2015
Discount Rate Percent	Total Proved
8	\$53,723
9	\$51,853
12	\$47,014
15	\$43,082

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the behind pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Sanchez's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward". The proved reserves included herein were estimated by deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Sanchez's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Sanchez owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or analogy, or a combination of these methods. The performance methods, such as decline curve analysis, utilized extrapolations of historical production and pressure data available through November 2015 where such data were considered to be definitive. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. The data utilized in this analysis were furnished to Ryder Scott by Sanchez or obtained from public data sources and were considered sufficient for the purpose thereof. Methods other than performance, such as analogies, were used on the remaining 10 percent of the proved producing reserves where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

All of the proved developed non-producing reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by Sanchez. The data utilized from the analogues and well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Sanchez has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Sanchez with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, abandonment costs after salvage, development costs, development plans, product prices based on SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Sanchez. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange

Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

The future production rates from wells currently on production may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Sanchez furnished us with the average prices in effect on December 31, 2015. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Sanchez. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Sanchez to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Avg Benchmark Prices	Avg Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$50.28/Bbl	$48.09/Bbl
	NGLs	Mt. Belvieu - Propane	$19.90/Bbl	$15.31/Bbl
	Gas	Henry Hub	$2.58/MMBTU	$2.61/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Sanchez and are based on the operating expense reports as provided by Sanchez and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Sanchez. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Sanchez and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Sanchez's estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Sanchez's estimate.

The proved behind pipe reserves in this report have been incorporated herein in accordance with Sanchez's plans to develop these reserves as of December 31, 2015. The implementation of Sanchez's development plans as presented to us and incorporated herein is subject to the approval process adopted by Sanchez's management. As the result of our inquiries during the course of preparing this report, Sanchez has informed us that the development activities included herein have been subjected to and received the internal approvals required by Sanchez's management at the appropriate local, regional and/or corporate level. Actual development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Sanchez. Additionally, Sanchez has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2015, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Sanchez. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Sanchez Production Partners LP.

Sanchez makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Sanchez has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Sanchez.

We have provided Sanchez with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Sanchez and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Don P. Griffin

Don P. Griffin, P.E.
TBPE License No. 64150
Senior Vice President

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Don P. Griffin was the primary technical person responsible for overseeing the estimate of the reserves, future production and income presented herein.

Mr. Griffin, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1981, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Griffin served in a number of engineering positions with Amoco Production Company. For more information regarding Mr. Griffin's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Griffin graduated with honors from Texas Tech University with a Bachelor of Science degree in Electrical Engineering in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Griffin fulfills. Mr. Griffin attended an additional 15 hours of training during 2015 covering such topics as reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Griffin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals which are open at the time of the estimate, but which have not started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) *Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.