UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON D.C. 20549

FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: **December 31, 2016**

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

COMMISSION FILE NUMBER: **000-55615**

ENERGY 11, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	**46-3070515**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification Number)
120 W 3rd Street, Suite 220 **Fort Worth, Texas**	**76102**
(Address of principal executive office)	(Zip Code)

Registrant's telephone number, including area code: **(817) 882-9192**

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

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Units of Limited Partnership Interest

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 Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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.

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 by Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

There is no established public market for the registrant's outstanding limited partnership interests. The registrant is continuing to conduct the ongoing initial public offering of its limited partnership interests (the "public offering") pursuant to its registration statement on Form S-1 (File No. 333-197476) at a per unit price of $20. The aggregate market value of the registrant's limited partnership interests held by non-affiliates of the registrant as of June 30, 2016 was $0.

As of March 3, 2017, the Partnership had 16,690,442 common units outstanding.

ENERGY 11, L.P.

FORM 10-K

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FORWARD LOOKING STATEMENTS

Certain statements within this report may constitute forward-looking statements. Forward-looking statements are those that do not relate solely to historical fact. They include, but are not limited to, any statement that may predict, forecast, indicate or imply future results, performance, achievements or events. You can identify these statements by the use of words such as “may,” “will,” “could,” “anticipate,” “believe,” “estimate,” “expect,” “intend,” “predict,” “continue,” “further,” “seek,” “plan” or “project” and variations of these words or comparable words or phrases of similar meaning.

These forward-looking statements include such things as:

- investment objectives and our ability to make investments in a timely manner on acceptable terms;
- references to future success in the Partnership’s property acquisition, drilling and marketing activities;
- our use of proceeds of the public offering and our business strategy;
- estimated future capital expenditures;
- estimated future distributions;
- sales of the Partnership’s properties and other liquidity events;
- competitive strengths and goals; and
- other similar matters.

These forward-looking statements reflect our current beliefs and expectations with respect to future events and are based on assumptions and are subject to risks and uncertainties and other factors outside our control that may cause actual results to differ materially from those projected. Such factors include, but are not limited to, those described under “Risk Factors” and the following:

- that our strategy of acquiring oil and gas properties on attractive terms and developing those properties may not be successful or, even if we successfully acquire properties, that our operations on such properties may not be successful;
- general economic, market, or business conditions;
- changes in laws or regulations;
- the risk that the wells in which we acquire an interest are productive, but do not produce enough revenue to return the investment made;
- the risk that the wells we drill do not find hydrocarbons in commercial quantities or, even if commercial quantities are encountered, that actual production is lower than expected on the productive life of wells is shorter than expected;
- current credit market conditions and our ability to obtain long-term financing for our property acquisitions and drilling activities in a timely manner and on terms that are consistent with what we project when we invest in a property;
- uncertainties concerning the price of oil and natural gas, which may decrease and remain low for prolonged periods; and
- the risk that any hedging policy we employ to reduce the effects of changes in the prices of our production will not be effective.

Although we believe the expectations reflected in such forward-looking statements are based upon reasonable assumptions, we cannot assure investors that our expectations will be attained or that any deviations will not be material. Investors are cautioned that forward-looking statements speak only as of the date they are made and that, except as required by law, we undertake no obligation to update these forward-looking statements to reflect any future events or circumstances. All subsequent written or oral forward-looking statements attributable to the Partnership or to individuals acting on its behalf are expressly qualified in their entirety by this section.

Item 1. Business

Energy 11, L.P. (the “Partnership,” “we” or “us”) was formed as a Delaware limited partnership in June 2013. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. In the public offering, we are offering common units of limited partners’ interests (the “common units”) on a best-efforts basis with the intention of raising up to $2,000,000,000 of capital, consisting of 100,263,158 common units. The registration statement with respect to the public offering was declared effective by the Securities and Exchange Commission ("SEC") on January 22, 2015. As of August 19, 2015, we completed the sale of the minimum offering of 1,315,790 common units. The subscribers were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time. As of December 31, 2016, the Partnership had sold 14.6 million common units for gross proceeds of $286.4 million and proceeds net of offering costs of $267.1 million. The offering will expire on the sooner of April 24, 2017 or the sale of 100,263,158 common units. As of March 3, 2017, we had 16,690,442 common units outstanding.

As of December 31, 2016, we own an approximate 11% working interest in approximately 216 existing producing wells and approximately 257 future development locations in the Sanish field located in Mountrail County, North Dakota (the "Sanish Field Assets"). The Sanish Field Assets are part of the Bakken shale formation in the Greater Williston Basin. On January 11, 2017, the Partnership completed the purchase of an additional 11% working interest in the Sanish Field Assets. All of our Sanish Field Assets are operated by Whiting Petroleum Corporation ("Whiting") (NYSE:WLL), a publicly traded oil and gas company.

The general partner of the Partnership is Energy 11 GP, LLC (the "General Partner").

Business Objective

Our primary investment objectives are to (i) acquire producing and non-producing oil and gas properties with development potential, and to enhance the value of the properties through drilling and other development activities, (ii) make distributions to the holders of the common units, (iii) engage in a liquidity transaction after five – seven years, in which all properties are sold and the sales proceeds are distributed to the partners, merge with another entity, or list the common units on a national securities exchange, and (iv) permit holders of common units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the common units primarily have been used to acquire a 22-23% working interest in the Sanish Field Assets and will be used to further develop these assets.

We were formed to acquire and develop oil and gas properties located onshore in the United States. We will manage and further develop our existing interests and as capital is available will look for additional interests in oil and gas properties.

Our Oil and Natural Gas Reserves

The table below summarizes our estimated net proved reserves as of December 31, 2016:

	As of December 31, 2016				
	Oil (MBbls)	**Natural Gas (MMcf)**	**NGLs (MBbls)**	**Total (MBOE)**	**Standardized Measure (2) (in thousands)**
Proved Reserves (1)					
Developed	4,748	5,163	631	6,240	$ 46,597
Undeveloped	4,042	4,804	587	5,431	14,349
Total Proved Reserves	8,790	9,967	1,218	11,670	$ 60,946

(1) Our proved reserves as of December 31, 2016 were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules based on unweighted arithmetic average prices as of the first day of each of the twelve months ended on such date. The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2016 were $42.75 per barrel of oil and $2.48 per MMcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2016 were $36.25 per barrel of oil, ($0.38) per MMcf of natural gas and $4.70 per barrel of NGL. See "Note 9 — Supplemental Oil and Natural Gas Disclosures (Unaudited)" in the accompanying notes to consolidated financial statements included elsewhere in this report for information concerning proved reserves.

(2) The standardized measure of discounted future net cash flows represents the estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation, in accordance with Accounting Standards Codification Topic 932 – Extractive Activities – Oil and Gas. Because we are a limited partnership, we are not subject to federal taxes in the calculation of the standardized measure. In addition, there are no entity level or gross receipts taxes in North Dakota, where all Partnership wells are located, that would give rise to an additional state tax provision.

The table above represents estimates only. Reserves estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Furthermore, different reserve engineers may make different estimates of reserves and cash flow based on the same available data and these differences may be significant. Therefore, these estimates are not precise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Prices for oil or natural gas at December 31, 2016 are above the average calculated for 2016. Sustained higher prices will have a positive impact to the estimated quantities and present values of our reserves; however, should prices decline, the estimated quantities and present values of our reserves will be reduced.

Current Developments

2017 Acquisition

As discussed above, the purchase of the additional 11% working interest in the Sanish Field Assets was completed on January 11, 2017. The purchase price was $130.0 million and was funded by the Partnership with $90.0 million in cash (from the sale of the Partnership's common units in its ongoing, best-efforts offering) and a $40.0 million promissory note ("Seller Note"). The Partnership paid the $40.0 million Seller Note in full on February 23, 2017. The Seller Note bore interest at 5% per annum up to the payoff date.

Management Agreement

At the initial closing of the sale of common units on August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with E11 Management LLC (the "Former Manager") to provide management and operating services regarding substantially all aspects of the Partnership. Under the Management Agreement, the Former Manager agreed to provide management and operating services to the Partnership in exchange for a monthly fee. In addition, the Partnership issued 100,000 Class B units to an affiliate of the Former Manager upon entering into the Management Agreement. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Distributions below.

The Former Manager was formed by Aubrey K. McClendon. The Management Agreement was terminable by the Partnership if, among other reasons, Mr. McClendon, the Former Manager's key employee, ceased to be employed by the Former Manager and the Partnership did not approve of a proposed replacement of such key employee. On March 2, 2016, Mr. McClendon died in a car accident. Following Mr. McClendon's death and subsequent correspondence between the Former Manager and the Partnership, on April 5, 2016, the Partnership elected not to approve a replacement key employee for Mr. McClendon and exercised its right to terminate the Management Agreement. Accordingly, the fees under the Management Agreement were no longer accrued as of the effective date of termination. Also, upon termination of the Management Agreement and in accordance with the terms therewith, 37.5% of the Class B units owned by Incentive Holdings were canceled. As of December 31, 2016, the Class B units owned by Incentive Holdings totaled 62,500. Since substantially all the Partnership's properties are operated by Whiting and the Partnership only owns a non-operating working interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting. Consequently, the termination of the Management Agreement has not had and the Partnership does not anticipate that the termination will have an adverse effect on its operations.

See further discussion in Note 6 titled "Management Agreement" In Part II, Item 8 of this Form 10-K.

Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors will oversee and review the Partnership's related party relationships and is required to approve any significant modifications to any existing related party transactions, as well as any new significant related party transactions.

See further discussion in Note 8 titled “Related Parties” in Part II, Item 8 of this Form 10-K.

Partners’ Equity and Distributions

As of December 31, 2016, the Partnership had sold 14.6 million common units for gross proceeds of $286.4 million and proceeds net of offering costs of $267.1 million. David Lerner Associates, Inc. is the dealer manager for the Partnership’s best-efforts offering (the “Dealer Manager”). Under the agreement with the Dealer Manager, the Dealer Manager receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership.

Prior to “Payout,” which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights (owned by the General Partner), with respect to Class B units or the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines “Payout Accrual” as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership’s assets, will be made as follows:

> First, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) to the Dealer Manager, as the contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any, to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the contingent incentive fee under the Dealer Manager Agreement;
>
> Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest.

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed above.

All items of income, gain, loss and deduction will be allocated to each Partner’s capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2016, the Partnership paid distributions of $1.40 per common unit or $10,448,981, and for the year ended December 31, 2015, the Partnership paid distributions of $0.51 per common unit or $1.3 million. The Partnership began paying distributions upon reaching the minimum offering in August 2015.

Internal Controls Over Reserve Estimates and Qualifications of Technical Persons

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with rules, regulations and guidance provided by the SEC, as well as established industry practices used by independent engineering firms and our peers, and in accordance with the SPE 2007 Standards promulgated by the Society of Petroleum Engineers. The Partnership engaged Pinnacle Energy Services, LLC (“Pinnacle Energy”) to prepare the reserve estimates for all of the Partnership’s assets for the year ended December 31, 2016 in this annual report. Pinnacle Energy founder J.P. Dick has over 30 years of experience in the oil and natural gas industry, with exposure to reserves and reserve related valuations and issues during that time, and is a Registered Professional Engineer in the states of Texas and Oklahoma. Further qualifications include a bachelor of science in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, Mr. Dick is an active participant in industry reserve seminars, professional industry groups and is a member of the Society of Petroleum Engineers.

Our controls over reserve estimates include engaging Pinnacle Energy as our independent petroleum engineer. We provided information about our oil and natural gas properties, including production profiles, prices and costs, to Pinnacle Energy and they prepared estimates of our reserves attributable to our properties. All of the information regarding reserves in this annual report on Form 10-K is derived from the report of Pinnacle Energy, which is included as an exhibit to this annual report on Form 10-K.

Our President works closely with our independent engineers, Pinnacle Energy, to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process as well as to review properties and discuss the methods and assumptions used by Pinnacle Energy in their preparation of the year-end reserve estimates. Our President also reviews the methods and assumptions used by Pinnacle Energy in the preparation of year end reserve estimates, and assesses them for reasonableness.

The Board of Directors of our General Partner also meets with our President to discuss matters and policies related to our reserves.

Our methodologies include reviews of production trends, analogy to comparable properties, and/or volumetric analysis. Performance methods are preferred. Reserve estimates for proved undeveloped properties are based primarily on volumetric analysis or analogy to offset production in the same or similar fields.

We apply and maintain internal controls, including but not limited to the following, to ensure the reliability of reserves estimations:

- no employee’s compensation is tied to the amount of reserves booked;
- we follow comprehensive SEC-compliant internal policies to determine and report proved reserves;
- reserve estimates are made by experienced reservoir engineers or under their direct supervision;
- annual review by the Board of Directors of our General Partner of our year-end reserve estimates prepared by Pinnacle Energy.
- each quarter, the Board of Directors of our General Partner reviews all significant reserves changes and all new proved undeveloped reserves additions.

Proved Undeveloped Reserves

At December 31, 2016, we had proved undeveloped reserves (“PUDs”) of approximately 5,430 MBOE, or approximately 47% of total proved reserves. Total PUDs at December 31, 2015 were 4,988 MBOE. The following table reflects the changes in PUDs during 2016:

	MBOE
Proved undeveloped reserves, December 31, 2015	4,988
Revisions of previous estimates	442
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430

Under current SEC requirements, PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years of their date of original booking unless specific circumstances justify a longer time. We will be required to remove our current PUDs if we do not drill those reserves within the required five-year time frame, unless specific circumstances justify a longer time. All of our PUDs at December 31, 2016 are scheduled to be drilled within five years of the date they were initially recorded. Historically, energy commodity prices have been volatile, and due to geopolitical risks in oil producing regions of the world as well as global supply and demand concerns, the Partnership continues to expect significant price volatility. Sustained lower prices for oil and natural gas may cause us in the future to forecast less capital to be available for development of our PUDs, which may cause us to decrease the number of our PUDs we expect to develop within the five year time frame. In addition, lower oil and natural gas prices may cause our PUDs to become uneconomic to develop, which would cause us to remove them from the proved undeveloped category.

Production, Prices and Production Cost History

The following table sets forth certain information regarding the production volumes, average prices received and average production costs associated with our sale of oil, natural gas, and natural gas liquids for the periods indicated below.

	Year (Period) Ended December 31,	
	2016	2015 (1)
Production (BOE):		
Oil	498,926	21,937
Natural gas	86,521	3,065
Natural gas liquids	69,059	2,841
Total	654,506	27,843
Average sales price per unit:		
Oil (per Bbl)	$ 36.50	$ 30.17
Natural gas (per Mcf)	2.43	1.47
Natural gas liquids (per Bbl)	12.97	5.29
Combined (per BOE)	31.12	25.28
Average unit cost per BOE:		
Production costs:		
Lease operating expenses	$ 5.81	$ 5.35
Gathering and processing expenses	2.66	0.60
Workover expenses	0.41	0.05
Production taxes	2.86	2.67
Total production costs	11.74	8.67
Depreciation, depletion and amortization	14.56	14.07

(1) All production and cost figures are derived from the Partnership's ownership of the properties from December 18, 2015 through December 31, 2015.

Delivery Commitments

As of December 31, 2016, we had no commitments to provide a fixed quantity of oil or natural gas.

Drilling Activity

During the first quarter of 2016, we completed the drilling of one well. We neither started nor completed any additional wells for the remainder of 2016.

Total Productive Wells

The following table sets forth information with respect to our ownership interest in productive wells as of December 31, 2016:

	December 31, 2016	
	Gross	Net
Oil wells:		
Sanish Field	216	23.1

Of the total well count for 2016, none are multiple completions.

Productive wells are producing wells and wells we deem mechanically capable of production, including shut-in wells, wells waiting for completion, plus wells that are drilled/cased and completed, but waiting for pipeline hook-up. A gross well is a well in which we own a working interest. The number of net wells represents the sum of fractional working interests the Partnership owns in gross wells.

Developed and Undeveloped Acreage Position

The following table sets forth information with respect to our gross and net developed and undeveloped oil and natural gas acreage under lease as of December 31, 2016, all of which is located in the State of North Dakota in the United States:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Sanish Field, Mountrail County, ND	34,269	4,564	-	-	34,269	4,564

As is customary in the oil and natural gas industry, we can generally retain an interest in undeveloped acreage through drilling activity that establishes commercial production sufficient to maintain the leases or by paying delay rentals during the remaining primary term of leases. The oil and natural gas leases in which we have an interest are for varying primary terms and, if production under a lease continues from developed lease acreage beyond the primary term, we are entitled to hold the lease for as long as oil or natural gas is produced. The oil and natural gas properties consist primarily of oil and natural gas wells and interests in developed leasehold acreage.

Undeveloped Acreage Expirations

The Partnership has no undeveloped acreage expirations as all acreage is held by production.

Marketing and Customers

The market for our oil and natural gas production depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, the demand for oil and natural gas, the marketing of competitive fuels and the effect of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Whiting, as operator of our properties, sells 99% of our production on our behalf.

Title to Properties

As is customary in our industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time we acquire properties. We believe that our title to all of the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in our operations. The interests owned by us may be subject to one or more royalty, overriding royalty, or other outstanding interests (including disputes related to such interests) customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations, and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as net profits interests, liens incident to operating agreements and current taxes, development obligations under oil and gas leases, and other encumbrances, easements, and restrictions, none of which detract substantially from the value of the interests or materially interfere with their use in our operations.

Insurance

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to our oil and gas properties, control of well, auto liability, marine liability, worker's compensation and employer's liability, among other things. Since we are not the operator of any of our properties, we rely on the insurance of the operator of our properties, of which our share of the cost is allocated back to the Partnership through the Joint Operating Agreement.

Currently, we have general liability insurance coverage up to $1,000,000 million per occurrence, which includes sudden and accidental environmental liability coverage for the effects of pollution on third parties arising from our operations. Our insurance policies contain maximum policy limits and in most cases, deductibles that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, we maintain excess liability coverage, which is in addition to and triggered if the general liability per occurrence limit is reached.

We re-evaluate the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Competition

The oil and natural gas industry is highly competitive. We will encounter strong competition from independent oil and gas companies, master limited partnerships and from major oil and gas companies in acquiring properties, contracting for drilling equipment and arranging the services of trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or other resources will permit.

We also may be affected by competition for drilling rigs, human resources and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in certain areas where we may acquire producing properties. These seasonal anomalies can pose challenges for meeting our drilling objectives and increase competition for equipment, supplies and personnel during the drilling season, which could lead to shortages and increased costs or delay our operations. Generally, demand for natural gas is higher in summer and winter months. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter natural gas requirements during off–peak months. This can lessen seasonal demand fluctuations.

Environmental, Health and Safety Matters and Regulation

Our operations are subject to stringent and complex federal, state and local laws and regulations that govern the protection of the environment 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;
- require the installation of pollution control equipment in connection with operations;
- place restrictions or regulations upon the use or disposal of the material utilized in our operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate or remediate pollution from former and ongoing operations, and may also require site restoration, pit closure and plugging of abandoned wells; and
- require the expenditure of significant amounts in connection with worker health and safety.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs. In general, the oil and natural gas industry has recently been the subject of increased legislation and regulatory attention with respect to environmental matters. The US Environmental Protection Agency, or EPA, has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2017 to 2019.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Solid and Hazardous Waste Handling

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous solid waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, we expect to generate waste as a routine part of our operations that may be subject to RCRA. Although a substantial amount of the waste expected to be generated in our operations is regulated as non–hazardous solid waste rather than hazardous waste, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous or exempt waste or categorize some non–hazardous or exempt waste as hazardous in the future. Any such change could result in substantial costs to manage and dispose of waste, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, imposes strict, joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so-called potentially responsible parties, or PRPs, include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts “petroleum” from the definition of hazardous substance, in the course of our expected operations, our properties may generate wastes that may fall within CERCLA’s definition of hazardous substance and may dispose of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum, and there is no guarantee that federal law will not adopt more stringent requirements with respect to the petroleum substances. We may also be the owner of sites on which hazardous substances have been released. If contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages. Further, we could be required to suspend or cease operations in contaminated areas.

We have and may acquire producing properties that have been used for oil and natural gas exploration and production for many years. Hazardous substances, wastes or hydrocarbons may have been released on or under the properties to be acquired by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of the properties we acquire may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Clean Water Act

The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous 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 state waters and 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. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non–compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and cleanup and response costs. The federal Clean Water Act only regulates surface waters. However most of the state analogs to the Clean Water Act also regulate discharges which impact groundwater.

Safe Drinking Water Act and Hydraulic Fracturing

Many of the properties we own and expect to acquire will require additional drilling operations to fully develop the reserves attributable to the properties. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities (except for fracturing activities involving the use of diesel).

Congress has repeatedly considered legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. A number of states, local and regional regulatory authorities have or are considering hydraulic fracturing regulation and other regulations imposing new or more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal, state, regional and local levels that could result in regulation of hydraulic fracturing becoming more stringent and costly. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. The EPA completed a wide-ranging study on the effects of hydraulic fracturing on drinking water resources and released its results in 2016. The EPA indicated that uncertainties and data gaps limited the EPA’s ability to fully assess impacts to drinking water resources locally and nationally, but hydraulic fracturing can impact drinking water under certain circumstances.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where we own properties that require additional drilling, we could incur substantial compliance costs and such requirements could adversely delay or restrict our ability to conduct fracturing activities on our assets.

Toxic Substances Control Act and Hydraulic Fracturing

On August 4, 2011, Earthjustice and 114 other organizations petitioned the EPA under section 21 of the Toxic Substances Control Act (TSCA) to use section 8(a) to require manufacturers and processors of oil and gas exploration and production (E&P) chemical substances and mixtures to maintain certain records and submit reports on those records; TSCA section 8(d) to require manufacturers, processors, and distributors to submit to the EPA existing health and safety studies related to E&P chemical substances and mixtures; TSCA section 8(c) to request submission of copies of any information related to significant adverse reactions to human health or the environment alleged to have been caused by E&P chemical substances and mixtures; and TSCA section 4 to require manufacturers and processors of E&P chemical substances and mixtures to conduct toxicity testing of E&P chemical substances and mixtures. In a letter dated November 2, 2011, the EPA informed petitioners that it denied the TSCA section 4 request and in a letter dated November 23, 2011, the EPA informed petitioners that it granted in part the TSCA section 8(a) and 8(d) requests. The document sets forth EPA's reasons for denying in part the petitioners' requests. In addition, the EPA has concluded that TSCA section 21 does not apply to requests for a TSCA section 8(c) data call-in. The EPA is launching a stakeholder and public engagement process to seek input on the design and scope of a system of reporting requirements. This is part of the EPA’s general review of hydraulic fracturing.

Oil Pollution Act

The primary federal law for oil spill liability is the Oil Pollution Act, or OPA, which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge on properties we own, we may be liable for costs and damages.

Air Emissions

Our operations are subject to the federal Clean Air Act, or CAA, and analogous state laws and local ordinances governing the control of emissions from sources of air pollution. The CAA and analogous state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or seek injunctive relief, requiring us to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation. The EPA rules include standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound, or VOC, emissions from natural gas not sent to the gathering line during well completion either by flaring, using a completion combustion device, or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of "green completions." The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. The EPA received numerous requests for reconsideration of these rules, and court challenges to the rules were also filed. The EPA has expressed an intent to issue some revisions that are likely responsive to some of the requests. For example, in September 2013, the EPA promulgated amendments related to certain storage vessels and in July 2014 proposed amendments related to well completion actions and to remove affirmative defense provisions. These rules and any revised rules may require the installation of equipment to control emissions on producing properties we acquire.

In 2015, the EPA proposed new rules limiting methane emissions from the oil and gas industry. The proposed rules, if adopted, would amend the air emissions rules for the oil and natural gas sources and natural gas processing and transmission sources to include new standards for methane. Simultaneously with the proposal of the methane rules, the EPA released a proposal soliciting comments on two alternatives for aggregating multiple surface sites into a single-source of air quality permitting purposes. Depending upon the alternative selected by the EPA, sites which currently would not require permitting under the Clean Air Act could require permits, an outcome that could result in costs and delays to our operations; however, given the present uncertainty regarding this rule, the extent and magnitude of that impact cannot be reliably or accurately estimated. In January 2016, BLM has proposed rules governing flaring and venting on public and tribal lands, which could require additional equipment and emissions controls and well as inspection requirements. If adopted or enacted, additional regulations on our air emissions is likely to result in increased compliance costs and additional operating restrictions on our business.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All proposed exploration and development plans on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs") may be adopted in the future and could cause us to incur material expenses in complying with them. Both houses of Congress have considered legislation to reduce emissions of GHGs, but no legislation has yet passed. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. Those measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and gas production sources and natural gas processing and transmission sources, the proposal of which is discussed above.

In addition, the EPA has adopted a mandatory GHG emissions reporting program that imposes reporting and monitoring requirements on various types of facilities and industries including onshore and offshore oil and natural gas production, processing, transmission, storage, and distribution facilities.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how and when federal regulation of GHGs might take place. Some members of Congress have expressed the intention to promote legislation to curb the EPA's authority to regulate GHGs. In addition to possible federal regulation, a number of states, individually and regionally as well as some localities, also are considering or have implemented GHG regulatory programs or other steps to reduce GHG emissions. These potential regional, state and local initiatives may result in so-called cap and trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in our incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from our operations. The federal, regional and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

Endangered Species Act

The Endangered Species Act was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities that would harm the species or that would adversely affect that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases that have species that are listed and species that could be listed as threatened or endangered under the act. The U.S. Fish and Wildlife Service designates the species' protected habitat as part of the effort to protect the species. A protected habitat designation or the mere presence of threatened or endangered species could result in material restrictions to our use of the land and may materially delay or prohibit land access for oil and natural gas development. It also may adversely impact the value of the affected properties that we acquire. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we might conduct operations could result in limitations or prohibitions on our activities and could adversely impact the value of our leases.

OSHA and Other Laws and Regulation

Our operators are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes require that employers organize and/or disclose information about hazardous materials used or produced in operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, local and tribal authorities. Rules and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making difficult the prediction of future costs or the impact of regulatory compliance attributable to new laws and statutes. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability. Our drilling and production operations will be subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states and some counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling, completing and operating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the marketing, transportation and reporting of production;
- notice to surface owners and other third parties; and
- produced water and waste disposal.

State and federal regulations are generally intended to prevent waste of oil and natural gas, protect correlative rights to produce oil and natural gas between owners in a common reservoir or formation, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to us are also subject to the jurisdiction of various federal, state and local authorities, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties.

States generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within their respective jurisdictions. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

In addition, a number of states and some tribal nations have enacted surface damage statutes, or SDAs. These laws are designed to compensate for damage caused by oil and natural gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and require specific payments by the operator to surface owners/users in connection with exploration and producing activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

We will not control the availability of transportation and processing facilities that may be used in the marketing of our production. For example, we may have to shut–in a productive natural gas well because of a lack of available natural gas gathering or transportation facilities.

If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non–discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by BLM, Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, Bureau of Indian Affairs, tribal or other appropriate federal, state and/or Indian tribal agencies.

The Mineral Leasing Act of 1920, or the Mineral Act, prohibits ownership of any direct or indirect interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign entity except through equity ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or entities of the United States. If these restrictions are violated, the oil and natural gas lease can be canceled in a proceeding instituted by the United States Attorney General. We qualify as an entity formed under the laws of the United States or of any U.S. State or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non–reciprocal countries, there are presently no such designations in effect. It is possible that our common unitholders may be citizens of foreign countries and do not own their common units in a U.S corporation or even if such interest is held through a U.S. corporation, their country of citizenship may be determined to be non–reciprocal countries under the Mineral Act. In such event, any federal onshore oil and natural gas leases held by us could be subject to cancellation based on such determination.

Federal Natural Gas Regulation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas are subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. FERC regulates the rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines under the Natural Gas Act as well as under Section 311 of the Natural Gas Policy Act.

Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, nondiscriminatory basis. FERC has announced several important transportation related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000, concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

FERC has also issued several other generally pro–competitive policy statements and initiatives affecting rates and other aspects of pipeline transportation of natural gas. On May 31, 2005, FERC generally reaffirmed its policy of allowing interstate pipelines to selectively discount their rates in order to meet competition from other interstate pipelines. On June 15, 2006, FERC issued an order in which it declined to establish uniform standards for natural gas quality and interchangeability, opting instead for a pipeline–by–pipeline approach. On June 19, 2006, in order to facilitate development of new storage capacity, FERC established criteria to allow providers to charge market–based (*i.e.*, negotiated) rates for storage services. On June 19, 2008, the FERC removed the rate ceiling on short–term releases by shippers of interstate pipeline transportation capacity.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the properties we may acquire. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

The pipelines used to gather and transport natural gas being produced by us are also subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), the Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act"), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk–based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In August 2011, the PHMSA issued an Advance Notice of Proposed Rulemaking regarding pipeline safety, including questions regarding the modification of regulations applicable to gathering lines in rural areas.

The U.S. Department of Energy ("DOE") regulates the export of natural gas produced in the U.S., including the export of liquefied natural gas ("LNG"), and the FERC regulates the construction and operation of liquefaction facilities used to convert gaseous natural gas into liquid for export as LNG. The DOE has granted several long-term LNG export licenses and FERC has authorized the construction and operation of several LNG export facilities for natural gas produced in the lower 48 States of the U.S., several of which are currently under construction. Beginning in 2016, cargo of LNG from the lower 48 States of the U.S. is being exported. It is too early to tell what impact this expansion of the markets available to natural gas produced in the U.S. will have on U.S. natural gas prices.

Other Regulation

In addition to the regulation of oil and natural gas pipeline transportation rates, the oil and natural gas industry generally is subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect upon our operations.

Employees

The Partnership has no officers, directors or employees. Instead, the General Partner manages the day-to-day affairs of the Partnership. All decisions regarding the management of the Partnership made by the General Partner will be made by the board of directors of the General Partner and its officers.

General Corporate Information

Energy 11, LP is a Delaware limited partnership founded in 2013 with principal offices at 120 W 3rd Street, Suite 220, Fort Worth, Texas 76102. We can be reached at (817) 882-9192 and our website address is www.energyeleven.com. The Partnership makes available, free of charge through its Internet website, its annual report on Form 10-K and quarterly reports on Form 10-Q, and amendments to those reports filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after the Partnership electronically files such material with, or furnishes it to, the SEC. Information contained on the Partnership's website is not incorporated by reference into this report.

Item 1A. Risk Factors

Risks Related to an Investment in the Partnership

Neither our chief executive officer nor our chief financial officer has any prior experience in investing in oil and gas properties.

The experience of our chief executive officer and our chief financial officer is primarily in the real estate industry. This is the first oil and gas program in which our chief executive officer and our chief financial officer have participated. The Partnership was originally formed with the intention of relying on the services of the Former Manager for primary oil and gas expertise and in identifying the location of suitable properties for acquisition. Since the Management Agreement has been terminated, the Partnership will no longer be able to rely upon the experienced personnel of the Former Manager. You should consider an investment in the Partnership in light of the risks, uncertainties and difficulties frequently encountered by management operating in a new industry.

The Partnership has limited prior operating history and this is the first oil and gas program sponsored by the General Partner and its affiliates.

The Partnership, which was formed in 2013, has limited operating history, and since its formation, the Partnership has not owned or operated any operating assets other than the Sanish Field Assets acquired on December 18, 2015. This is the first oil and gas program sponsored by the general partner and its affiliates. You should consider an investment in the Partnership in light of the risks, uncertainties and difficulties frequently encountered by companies that are, like the Partnership, in their early stage of development. The Partnership cannot guarantee that it will succeed in achieving its goals, and its failure to do so could cause you to lose all or a portion of your investment.

Because we have not yet identified or selected all properties that we may acquire, this is a "blind pool" offering. This means you may not be able to evaluate all of the Partnership's properties before making your investment decision.

On December 18, 2015, the Partnership acquired the Sanish Field Assets and in January 2017, the Partnership acquired additional working interests in the Sanish Field Assets. We have not selected any other properties for acquisition by the Partnership and may not select additional properties for acquisition until after you invest in the Partnership. You may not have an opportunity before purchasing units to evaluate geophysical, geological, economic or other pertinent information regarding any additional prospects to be selected. If we select additional properties for acquisition by the Partnership during the offering period, we will file a prospectus supplement describing the properties and their proposed acquisition. If you subscribe for units prior to any such supplement you will not be permitted to withdraw your subscription as a result of the selection of any property.

The common units are not liquid and your ability to resell your common units will be limited by the absence of a public trading market and substantial transfer restrictions.

The common units generally will not be liquid because there is not a readily available market for the sale of common units, and one is not expected to develop. Further, although our Partnership Agreement contains provisions designed to permit the listing of common units on a national securities exchange, the Partnership does not currently intend to list the common units on any exchange or in the over-the-counter market.

Our distributions to our common unitholders may not be sourced from our cash generated from operations but from offering proceeds or indebtedness, and therefore our distributions during certain periods may exceed earnings and cash flows from operations, and this will decrease our distributions in the future; furthermore, we cannot guarantee that investors will receive any specific return on their investment.

Our General Partner has the right to make distributions from the proceeds of borrowings and capital contributions. It is likely that all or a part of distributions to common unitholders during the early years of our operations will represent the proceeds of capital contributions, rather than cash generated in our operations. This is because as proceeds are raised in the public offering, it is not always possible immediately to invest them in oil and gas properties that generate our desired return on investment. There may be a "lag" or delay between the raising of offering proceeds and their investment in oil and gas properties. Investors who acquire common units relatively early in our public offering, as compared with later investors, may receive a greater return of offering proceeds as part of the earlier distributions. Offering proceeds that are returned to investors as part of distributions to them will not be available for investments in oil and gas properties. In addition, during certain periods, we expect that distributions may exceed the amount of earnings and cash flows from operations during such periods. The payment of distributions will decrease the cash available to invest in oil and gas properties and will reduce the amount of distributions we may make in the future. We cannot and do not guarantee that investors will receive any specific return on their investment. Further, there is no limitation on the amount of distributions that can be funded from offering proceeds or indebtedness. Because cash generated from our operations will be comingled and is fungible with cash received from capital contributions and indebtedness, we are unable to determine a point in time when distributions will no longer be sourced from capital contributions.

Moreover, as a result of the Seller Note indebtedness we incurred in connection with the January 2017 Sanish Field Assets acquisition, we will use a portion of our cash flow to pay interest on and principal of this indebtedness when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate.

If the General Partner elects to cause us to make distributions rather than reinvesting the cash flow in our business, we may be required to sell or farm-out properties or to elect not to participate in exploration or development drilling activities on our properties, which activities could turn out to be profitable.

If the Partnership were presented with an exploration or development drilling or other opportunity on its properties, and funding the opportunity would require the Partnership's cash that is required in order to follow its distribution policy or for other purposes approved by our General Partner, our General Partner may elect to cause the Partnership to sell or farm-out the opportunity or decline to participate in the opportunity, even if the General Partner determines that the opportunity could have a favorable rate of return. Our General Partner will have the right to cause the Partnership to participate in opportunities that will use the Partnership's cash otherwise than in accordance with the distribution policy if the General Partner determines that pursuing such opportunity is in the best interests of the Partnership.

Our General Partner will be subject to conflicts of interest in operating our business, including conflicts of interest arising out of the General Partner's ownership of the incentive distribution rights. Our Partnership Agreement limits the General Partner's fiduciary duties to us in connection with these conflicts of interest.

The General Partner will be subject to conflicts of interest in operating our business. These conflicts include:

- Conflicts caused by the incentive distribution rights held by the General Partner, which may cause it to acquire properties or conduct operations that are more risky to the Partnership, or to sell properties, in order to generate distributions from the incentive distribution rights;
- Conflicts caused by the sale of properties to programs that have or may be formed by the General Partner and its affiliates in the future; and
- Conflicts caused by competition for management time and attention with other oil and gas partnerships and with other business activities in which management of our General Partner are or may be involved.

Our Partnership Agreement provides that our General Partner will have no liability to the Partnership or the holders of the common units for decisions made, if such decisions are made in good faith. In addition, our Partnership Agreement provides that if the General Partner receives a fairness opinion regarding the sale price of a property or in connection with a merger or the listing of our common units on a national securities exchange, including transactions that involve affiliates of the General Partner, the General Partner will be deemed to have acted in good faith.

Amounts paid to our General Partner regardless of success of the Partnership's activities will reduce the cash we have available for distribution.

The General Partner and its affiliates will receive reimbursement of third-party costs incurred in connection with the formation of the Partnership and the Partnership's business activities and will be reimbursed for general and administrative costs of the General Partner allocable to the Partnership as described in "Compensation" within the Partnership's prospectus, regardless of the Partnership's success in acquiring, developing and operating properties. The fees and direct costs to be paid to the General Partner will reduce the amount of cash distributions to investors. With respect to third-party costs, the General Partner has sole discretion on behalf of the Partnership to select the provider of the services or goods and the provider's compensation.

Because our General Partner has discretion to determine the amount and timing of any distribution we may make, there is no guaranty that cash distributions will be paid by the Partnership in any amount or frequency even if our operations generate revenues.

The timing and amount of distributions will be determined in the sole discretion of the General Partner. The level of distributions, when made, will primarily be dependent upon the Partnership's levels of revenue, among other factors. Distributions may be reduced or deferred, in the discretion of the General Partner, to the extent that the Partnership's revenues are used or reserved for any of the following:

- compensation and fees paid to the General Partner and its affiliates as described above in "— Amounts paid to our General Partner regardless of success of the Partnership's activities will reduce the cash available for distribution;"
- repayment of borrowings;
- drilling and completing new wells;
- cost overruns on drilling, completion or operating activities;
- remedial work to improve a well's producing capability;
- the acquisition of producing and non-producing oil and gas leasehold interests considered in the best interest of the Partnership by the General Partner;
- uninsured losses from operational risks including liability for environmental damages;
- direct costs and general and administrative expenses of the Partnership;
- reserves, including a reserve for the estimated costs of eventually plugging and abandoning the wells; or
- indemnification of the General Partner and its affiliates by the Partnership for losses or liabilities incurred in connection with the Partnership's activities.

Further, because the Partnership's investments will be in depleting assets, unless reinvested, Partnership revenues and the amount available for distribution to partners will decline with the passage of time. Accordingly, there can be no assurance that the Partnership will be able to make regular distributions or that distributions will be made at any consistent rate or frequency.

We may be unable to sell our properties, merge with another entity or list the common units on a national securities exchange within our planned timeline or at all.

Beginning five to seven years after the termination of the Partnership's public offering, we plan either to sell our properties and distribute the proceeds of the sale, after payment of liabilities and expenses, to our partners, merge with another entity, or list the common units on a national securities exchange. The decision to sell our properties or merge with another entity will be based on a number of factors, including the domestic and foreign supply of and demand for oil, natural gas and other hydrocarbons, commodity prices, demand for oil and natural gas assets in general, the value of our assets, the projected amount of our oil and gas reserves, general economic conditions and other factors that are out of our control. In addition, the ability to list our common units on a national securities exchange will depend on a number of factors, including the state of the U.S. securities markets, our ability to meet the listing requirements of national securities exchanges, securities laws and regulations and other factors. If we are unable to either sell our properties, merge or list the common units on a national securities exchange in accordance with our current plans, you may be unable to sell or otherwise transfer your common units and you may lose some or all of your investment.

The ability to spread the risks of property acquisitions among a number of properties will be reduced if less than the maximum offering proceeds are received and fewer acquisitions are consummated.

The Partnership was required to receive minimum offering proceeds of $25,000,000 to break escrow, and the Partnership's maximum offering proceeds may not exceed $2,000,000,000. The minimum offering was reached on August 19, 2015 and the offering expires in April 2017. There are no other requirements regarding the amount of offering proceeds to be received by the Partnership. Generally, the less offering proceeds received the fewer properties the Partnership would acquire, which would decrease the Partnership's ability to spread the risks of acquisition and development of the Partnership's properties. As of January 31, 2017, all of the Partnership's investments are in the Sanish Field Assets.

Our lack of geographical diversification may increase the risk of an investment in the Partnership.

All of the Partnership's assets are located in concentrated areas of the Williston Basin in Mountrail County, North Dakota. While other companies and limited partnerships may have the ability to manage their risk by diversification, the narrow geographic focus of our business means that we may be impacted more acutely by factors affecting our industry or the region in which we operate than we would if our asset locations were more diversified. We may be disproportionately exposed to the effects of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of oil or natural gas. Additionally, the Partnership may be exposed to further risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within the Williston Basin. The Partnership does not currently intend to broaden the geographic scope of its asset base.

The amount of indebtedness that the Partnership may incur is not limited by the terms of the Partnership Agreement.

The General Partner intends to limit the amount of borrowing to 50% of the Partnership's total capitalization on an annual basis. However, the Partnership Agreement does not place any limitation on the amount of indebtedness that the General Partner may cause the Partnership to incur, and holders of common units will have no right to control or influence the amount of indebtedness the Partnership incurs. High levels of indebtedness may have adverse consequences for the Partnership, including:

- Cash that would otherwise be available for distribution or to invest in the Partnership's business will be used to pay interest on indebtedness;
- Covenants in the indebtedness may restrict the Partnership's ability to conduct its business, to make acquisitions or develop its assets and to make distributions; and
- Default in the repayment of indebtedness could result in foreclosure on the Partnership's assets, or require the Partnership to refinance indebtedness at higher costs.

We may have indebtedness under a credit facility. Restrictions in a credit facility may limit our ability to make distributions to holders of our common units and may limit our ability to capitalize on acquisitions and other business opportunities.

We expect that any credit facility we are able to negotiate will contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, make investments or dispositions and engage in transactions with affiliates, as well as covenants requiring us to maintain certain financial ratios and tests. In addition, the borrowing base under our anticipated facility will be subject to periodic review by our lenders. Difficulties in the credit markets may cause the banks to be more restrictive when redetermining our borrowing base.

Our General Partner has sole responsibility for conducting our business and managing our operations. Our General Partner and its affiliates will have conflicts of interest, which may permit them to favor their own interests to the detriment of holders of our common units.

Conflicts of interest may arise between our General Partner, Energy 11 GP, LLC, and its respective affiliates on the one hand, and us and the holders of our common units, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its owners over the interests of holders of our common units. These conflicts include, among others, the following situations:

- neither our Partnership Agreement nor any other agreement requires affiliates of our General Partner to pursue a business strategy that favors us or to refer any business opportunity to us;
- our General Partner determines the amount and timing of our asset purchases and sales, capital expenditures and borrowings, each of which can affect the amount of cash that is distributed to holders of our common units or used to service our debt obligations;
- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates; and
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

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.

Our Partnership Agreement contains provisions that reduce or eliminate the fiduciary and other duties that our General Partner, its board of directors (and any committee thereof) and its officers and the other persons who control it might have otherwise owed to us and the holders of our common units. In taking any action or making any decision on behalf of the General Partner or us, such persons will be presumed to have acted in good faith and, in any proceeding brought by or on behalf of any holder of common units or us, the person bringing such proceeding will have the burden of overcoming such presumption.

Furthermore, under our Partnership Agreement, our General Partner, its board of directors (and any committee thereof), its affiliates and the directors, officers and other persons who control our General Partner or any of its affiliates will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such person acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

Holders of our common units have limited voting rights and are not entitled to elect or remove our General Partner or the board of directors of our General Partner.

Unlike the holders of common stock in a corporation, common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Common unitholders will not elect our General Partner, or the members of its board of directors, and will have no right to remove our General Partner, or its board of directors. The board of directors of our General Partner is chosen by the owners of Energy 11 GP, LLC, our General Partner.

Your liability may not be limited if a court finds that common 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 plan to conduct business in a number of other states. 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 may 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 determined 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 common unitholders to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitutes "control" of our business.

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

Under certain circumstances, common unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17–607 of the Delaware Revised Uniform Limited Partnership 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 the 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. Substituted limited partners are liable for the obligations of the assignor to make contributions to a partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the Partnership Agreement. Liabilities to partners on account of their partnership interest and liabilities that are non–recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Fees and cost reimbursements that must be paid to our General Partner and the dealer manager regardless of success of the Partnership's activities will reduce the cash we have available for distribution.

The General Partner and its affiliates will receive reimbursement of third-party costs incurred in connection with the formation of the Partnership and the Partnership's business activities and will be reimbursed for general and administrative costs of the General Partner allocable to the Partnership regardless of the Partnership's success in acquiring, developing and operating properties. The dealer manager will receive sales commissions, marketing fees, the contingent, incentive fee and account maintenance fees in connection with the public offering. The fees and direct costs to be paid to the General Partner and the dealer manager will reduce the amount of cash distributions to investors.

Common units may be purchased by individuals who have an interest in the public offering different from yours.

The owners of our General Partner have each purchased 5,000 common units for $20.00 per unit. In addition, the partnership agreement does not restrict the ability of any other service providers or vendors to the Partnership from purchasing common units. In addition, if a matter were to be submitted to a vote of holders of common units, the owners of our General Partner or other service providers or vendors who purchase common units may have different interests from other holders of common units in voting their common units.

Risks Related to Our Business

We will have limited control over the activities on properties we do not operate.

Whiting operates 99% of the properties in which we hold a working interest. We have limited ability to influence or control the operation or future development of the non-operated properties or the amount of capital expenditures that we are required to fund. The failure of Whiting to adequately perform operations, breach the applicable agreements or failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on Whiting and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

We will need additional funding for the Sanish Field Assets in order to retain our full interest therein.

We anticipate that we will be obligated to significantly invest in drilling capital expenditures within the next five years to retain our working interest in the Sanish Field Assets without becoming subject to non-consent penalties under the joint operating agreements governing those properties. We will depend, at least in part, on continued sales pursuant to the terms of this Offering, increased cash flow from operations and possibly indebtedness to fund the anticipated capital expenditures needed to retain our full interest in these assets. None of these funding sources is guaranteed, and if we are unable to obtain all of this funding we may lose all or a portion of the assets acquired, and our results of operations will be negatively affected accordingly.

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our General Partner, to enable us to make cash distributions to holders of our common units under our cash distribution policy.

We may not have sufficient available cash each month to enable us to make cash distributions to the holders of common units. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from month to month based on, among other things:

- the amount of oil, natural gas and natural gas liquids we produce;
- the prices at which we sell our production;
- our ability to hedge commodity prices at economically attractive prices;
- the level of our capital expenditures;
- the level of our operating and administrative costs including reimbursement to our General Partner; and
- the level of our interest expense, which depends on the amount of any future indebtedness and the interest payable thereon.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the amount of cash reserves established by our General Partner for the proper conduct of our business and for capital expenditures, which may be substantial;
- the cost of acquisitions, operations, infrastructure and drilling;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds;
- the timing and collectability of receivables; and
- prevailing economic conditions.

As a result of these factors, the amount of cash we distribute to holders of our common units may fluctuate significantly from month to month.

If oil, natural gas or other hydrocarbon prices are depressed for a prolonged period, our cash flows from operations will decline and we may have to lower our distributions or may not be able to pay distributions at all.

Our revenue, profitability and cash flow depend upon the prices for oil, natural gas and other hydrocarbons. The prices we will receive for our production will be volatile and a drop in prices can significantly affect our financial results and adversely affect our ability to maintain our borrowing capacity and to repay indebtedness, all of which can affect our ability to pay distributions. Changes in prices have a significant impact on the value of our reserves and on our cash flows. Prices may fluctuate widely in response to relatively minor changes in supply and demand, 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, natural gas and other hydrocarbons;
- regulations which may prevent or limit the export of oil, natural gas and other hydrocarbons;
- the amount of added production from development of unconventional natural gas reserves;
- the price and quantity of foreign imports of oil, natural gas and other hydrocarbons;
- the level of consumer product demand;
- weather conditions and natural disasters;

- the value of the U.S dollar relative to the currencies of other countries;
- overall domestic and global economic conditions;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, conditions in South America, China and Russia, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- technological advances affecting energy production and consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of oil, natural gas and other hydrocarbon pipelines and other transportation facilities to our production;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas; and
- the price and availability of alternative fuels.

Low oil, natural gas and other hydrocarbon prices will decrease our revenues, but may also reduce the amount of oil, natural gas or other hydrocarbons that we can economically produce. 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 non–cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under any credit facility, which may adversely affect our ability to make cash distributions to holders of our common units and service our debt obligations.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We own less than 100% of the working interest in the Sanish Field Assets, and other parties own the remaining portion of the working interests. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person or entity. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of the other working interest owners, particularly those that are smaller and less established, will not be able to fulfill their joint activity obligations. Another working interest owner may be unable or unwilling to pay its share of project costs, and, in some cases, may declare bankruptcy. In the event any of our co-owners do not pay their share of such costs, we would likely have to pay our share of those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

Because we will depend on our general partner and its affiliates to conduct our operations, any adverse changes in the financial health of our general partner or our relationship with them could hinder our operating performance and ability to make distributions.

We will depend on our general partner and its affiliates and possibly other third party operators, for the acquisition, development and operation of our properties. Our general partner has been recently formed and has limited prior operating history. Any adverse changes in the financial condition of the general partner or in our relationship with them could hinder its or their ability to successfully manage our operations.

Properties that we buy or develop may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could adversely affect our cash available for distribution.

Any future acquisition or decision to develop a property we have acquired will require an assessment of recoverable reserves, title, future oil, natural gas and natural gas liquids prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Reserve estimates may be prepared internally by us or by a third party. The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors such as future oil and gas prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds, all of which can be difficult to predict with accuracy. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. We expect that our review efforts will be focused on the higher valued properties in our acquisitions and will be inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations and our ability to make cash distributions to holders of our common units.

Additional potential risks related to the acquisition and development include, among other things:

- incorrect assumptions regarding the future prices of oil, natural gas and other hydrocarbons or the future operating or development costs of properties acquired;
- incorrect estimates of the reserves and projected development results attributable to a property we acquire;
- drilling, operating and other cost overruns;
- an inability to integrate successfully the properties we acquire;
- the assumption of liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management’s attention from other business concerns; and
- losses of key employees.

We may engage in exploration activities on properties we acquire which activities are more risky than development activities.

We expect to acquire oil and gas properties which require additional drilling and other exploitation activities to fully develop. Some of the drilling on our properties may be classified as exploration drilling. Exploration drilling is inherently more risky than development drilling. Although we expect that our exploration drilling will be located near areas which have undergone successful drilling or in areas with geological characteristics similar to areas which have been successfully developed, no assurances can be made that the Partnership’s exploration or development drilling will be successful in discovering producible oil and gas reserves.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from dense rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We will routinely use hydraulic fracturing techniques in most of our drilling and completion programs. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. In addition, legislation has repeatedly been introduced before Congress to provide for federal regulation of hydraulic fracturing using materials other than diesel under the Safe Drinking Water Act and to require disclosure of the chemicals used in the fracturing process. At the state and local levels, some jurisdictions have adopted, and others are considering adopting, requirements that could impose more stringent permitting, public disclosure of fracturing chemicals or well construction requirements on hydraulic fracturing activities, as well as bans on hydraulic fracturing activities. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we acquire producing properties, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells. More widespread or prolonged moratoriums or prohibitions of hydraulic fracturing could, depending on the makeup of our assets, cause the Partnership to cease business operations.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has released its results of a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, indicating that uncertainties and data gaps limited the EPA's ability to fully assess impacts to drinking water resources locally and nationally, but hydraulic fracturing can impact drinking water under certain circumstances. Other ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Moreover, the EPA proposed effluent limitations for the pretreatment and discharge of wastewater resulting from hydraulic fracturing activities to publicly owned treatment works. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. Further, the Bureau of Land Management has adopted final rules regulating hydraulic fracturing on public lands. These rules include requirements on drillers to disclose the chemicals used in hydraulic fracturing operations and new requirements for well casing, groundwater protections, and wastewater storage. We are currently evaluating the impact of these rules on our operations. The EPA has also announced an initiative under the Toxic Substance Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals If hydraulic fracturing is further regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operations restrictions and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we ultimately are able to produce.

Our hedging transactions will expose us to counterparty credit risk.

We may engage in hedging transactions to reduce, but not eliminate, the effect of volatility in oil, gas and other hydrocarbon prices. Our hedging transactions will expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of falling commodity prices, such as those that occurred in late 2008 and 2012, our hedge receivable positions will increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Our hedging activities could result in financial losses or could reduce our net income, which may adversely affect our ability to pay cash distributions to holders of our common units.

To achieve more predictable cash flows and to reduce our exposure to fluctuations in the prices of oil, natural gas and other hydrocarbons, we may enter into hedging arrangements for a significant portion of our estimated future production. If we experience a sustained material interruption in our production, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flows from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity.

Our ability to use hedging transactions to protect us from future price declines will be dependent upon oil and natural gas prices at the time we enter into future hedging transactions and our future levels of hedging, and as a result our future net cash flows may be more sensitive to commodity price changes. Additionally, it may not be possible or economic to hedge all of the hydrocarbons that we produce because of the lack of a market for such hedges or other reasons. We may hedge certain hydrocarbons we produce by entering into swaps, collars or other contracts covering hydrocarbons we consider to be priced similarly to the hydrocarbons we produce, and could be subject to losses if the prices for the hydrocarbons we produce do not match the hydrocarbons we contract for.

Our policy will be to hedge a portion of our near–term estimated production. The prices at which we hedge our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially higher or lower than current oil, natural gas and other hydrocarbon prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from commodity price increases. It is also possible that a substantially larger percentage of our future production will not be hedged as compared with the next few years, which would result in our oil, natural gas and natural gas liquids revenues becoming more sensitive to commodity price changes. Our General Partner will not be liable for any losses we incur as a result of our hedging policy or the implementation of that policy.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

During 2010, President Obama signed into law the Dodd–Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act. Among other things, the Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over–the–counter market.

In its rulemaking under the new legislation, the CFTC has issued numerous new regulations, including on November 5, 2013, a proposed rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain *bona fide* hedging transactions). The CFTC has not yet issued a final rule on position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

The Dodd-Frank Act and the regulations enacted thereunder by the CFTC generally mandate that all swaps are required to be: (i) cleared through derivatives clearing organizations, (ii) traded on registered exchanges, and (iii) subject to mandatory posting of initial and variation margin as credit support. In addition, the Dodd-Frank Act and the CFTC's regulations thereunder provide exemptions for commercial end users (such as us) using swaps to hedge their commercial risk from these clearing, exchange-trading and margin-posting requirements, thereby allowing commercial end-users to enter into over–the–counter, bilaterally negotiated swaps for their hedging transactions. The CFTC has not yet issued a final rule on capital requirements for swap dealers. However, it is possible that our counterparties in respect of their over-the-counter (i.e., uncleared) hedging transactions with us will be subject to capital requirements. Similarly, with respect to our counterparties' uncleared swaps with third parties entered into in order to perform under their uncleared hedging transactions with us, our counterparties may be subject to margin-posting requirements. If the regulations ultimately adopted require our counterparties to maintain higher capital levels or to post margin in connection with entering into hedging transactions with us, the costs of which could be passed through to us, then our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reforms required by the Dodd-Frank Act may also require our hedging counterparties to spin off some of their derivative activities to separate entities, which may not be as creditworthy as our current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, restrict our flexibility in conducting trading and hedging activity and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may be more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas and other hydrocarbon prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and other hydrocarbons. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices.

The financial conditions of our hydrocarbon purchasers could have an adverse impact on us in the event these purchasers are unable to pay us for our oil and gas production.

Some of our hydrocarbon purchasers may experience, in the future, severe financial problems that may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our hydrocarbon purchasers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our hydrocarbon purchasers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed. In addition, such events might force such purchasers to reduce or curtail their future purchase of our production and services, which could have a material adverse effect on our results of operations and financial condition.

We plan to rely on drilling to fully develop the properties we acquire. If our drilling is unsuccessful, our cash available for distributions and financial condition will be adversely affected.

We have and plan to acquire oil and gas properties that are not fully developed, and require that we engage in drilling to fully exploit the reserves attributable to the properties. Our drilling will involve numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We may incur significant expenditures to drill and complete wells, including cost overruns. Additionally, current geoscience technology may not allow us to know conclusively, prior to drilling a well, that oil or natural gas is present or economically producible. The costs of drilling and completing wells are often uncertain, and it is possible that we will make substantial expenditures on drilling and not discover reserves in commercially viable quantities. These expenditures will reduce cash available for distribution to holders of our common units and for servicing any debt obligations.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

unexpected drilling or operating conditions;
facility or equipment failure or accidents;
shortages or delays in the availability of drilling rigs and equipment and in hiring qualified personnel;
adverse weather conditions;
shortages of water required for hydraulic fracturing or other operations;
compliance with environmental and governmental requirements;
reductions in oil or gas prices;
proximity to and capacity of transportation and processing facilities;
title problems;
encountering abnormal pressures or unusual, unexpected or irregular geological formations;
pipeline ruptures;
fires, blowouts, craterings and explosions; and
uncontrollable flows of oil or natural gas or well fluids.

Even if drilled, completed wells may not produce quantities of oil or natural gas that are economically viable or that meet earlier estimates of economically recoverable reserves. A productive well may become uneconomic if water or other deleterious substances are encountered, which impair or prevent the production of oil and/or natural gas from the well. Our overall drilling success rate or drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial condition by reducing our available cash and resources.

We must find or acquire economically recoverable reserves to sustain production and future cash flows. If we are unable to find or acquire reserves, our future financial condition will be adversely affected.

Our continued success depends upon our ability to find, develop and acquire oil and gas reserves that are economically recoverable. If we do not drill suitable prospects, you are unlikely to realize your investment expectations.

In addition, our future oil and natural gas production will depend on our success in finding or acquiring additional reserves. If we are unable to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful acquisition and development activities. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in developing or acquiring additional reserves.

Our business is subject to operational risks that will not be fully insured, which, if they were to occur, could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to holders of our common units and service our debt obligations.

Our business activities are subject to operational risks, including:

- damages to equipment caused by adverse weather conditions, including tornadoes, drought and flooding;
- unexpected formations and pressures;
- facility or equipment malfunctions;
- pipeline ruptures or spills;
- fires, blowouts, craterings and explosions;
- release of toxic gasses;
- uncontrollable flows of oil or natural gas or well fluids; and
- surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

Any of these events could adversely affect our operator’s ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension cessation or of operations, and attorneys’ fees and other expenses incurred in the prosecution or defense of litigation and could also result in requirements to remediate, regulatory investigations, and/or the interruption of our business and/or the business of third parties.

As is customary in the industry, we will maintain insurance against some but not all of these risks. Additionally, 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 activities, financial condition, results of operations and ability to pay distributions to holders of our common units and service our debt obligations.

Our financial condition and results of operations may be materially adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including, for example:

- the Clean Air Act, or the CAA, and comparable state laws and regulations that impose obligations related to emissions of air pollutants;
- the Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated water;
- the Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities;
- the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal;
- the Safe Drinking Water Act and state or local laws and regulations related to underground injection (including hydraulic fracturing);
- the Endangered Species Act and comparable state and local laws and regulations which protect endangered and threatened species and the ecosystems on which they depend;
- the National Environmental Policy Act and comparable state statutes which ensure that environmental issues are adequately addressed in decisions involving major governmental actions (including the leasing of government land);
- the Toxic Substances Control Act and comparable state statutes which regulate the manufacture, use, distribution and disposal of chemical substances;
- the Oil Pollution Act, or OPA, which subject responsible parties to liability for removal costs and damages arising from an oil spill in waters of the U.S.; and

emergency planning and community right to know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations.

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. Certain environmental statutes, including CERCLA, OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released. More stringent laws and regulations, including any related to climate change and greenhouse gases, may be adopted in the future. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our business is subject to complex and stringent laws and regulations governing the acquisition, development, operation, production and marketing of oil and gas, taxation, safety matters and the discharge of materials into the environment. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining and maintaining regulatory approvals 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 resource conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil, natural gas and natural gas liquids we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil, natural gas and natural gas liquids. While the cost of compliance with these laws is not expected to be material to our operations, the possibility exist that new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to pay distributions to holders of our common units and service our debt obligations could be adversely affected.

Climate change legislation or regulations restricting emissions of greenhouse gases, or GHGs, could result in increased operating costs and reduced demand for the oil, natural gas and natural gas liquids we produce.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants. These permitting provisions, to the extent applicable to our operations, could require us to implement emission controls or other measures to reduce GHG emissions and we could incur additional costs to satisfy those requirements. Further, the EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. Those measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and gas production sources and natural gas processing and transmission sources.

In addition, the EPA requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis. We are in the process of evaluating whether our operations trigger this requirements. In past years, we have not triggered the reporting obligation and continue to evaluate annually whether we trigger this requirement; should we trigger the reporting requirement, we will incur costs associated with the reporting obligation.

In past legislative sessions, Congress considered legislation to reduce emissions of GHGs and many states and regions have adopted or have considered measures to reduce GHG emission reduction levels, often involving the planned development of GHG emission inventories and/or cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. Federal efforts at a cap and trade program have not moved forward in Congress. Some members of Congress have publicly indicated an intention to introduce legislation to curb the EPA's regulatory authority over GHGs. The adoption and implementation of any legislation or regulatory programs imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil, natural gas and natural gas liquids that we produce.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, the operations that we plan to engage in may be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. Should drought conditions occur, our ability to obtain water in sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

We expect to be subject to regulation under New Source Performance Standards, or NSPS, and National Emissions Standards for Hazardous Air Pollutants, or NESHAP programs, which could result in increased operating costs.

On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and the NESHAP programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards required owners/operators to reduce volatile organic compound, or VOC, emissions from natural gas not sent to the gathering line during well completion either by flaring, using a completion combustion device, or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also established specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules and any revised rules may require the installation of equipment to control emissions on producing properties we acquire.

We may encounter obstacles to marketing our oil, natural gas and other hydrocarbons, which could adversely impact our revenues.

The marketability of our production will depend upon numerous factors beyond our control, including the availability and capacity of natural gas gathering systems, pipelines and other transportation and processing facilities that we expect to be owned by third parties. Transportation space on the gathering systems and pipelines we expect to utilize is occasionally limited or unavailable due to repairs or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. Our operator's access to transportation and processing options and the marketing of our production can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, as well as the other risks discussed in this report. The availability of markets are beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil, natural gas and natural gas liquids, the value of our common units and our ability to pay distributions on our common units.

We may be required to shut-in wells or delay initial production for lack of a viable market or because of the inadequacy or unavailability of pipeline, gathering system, processing, treating, fractionation or refining capacity. When that occurs, we will be unable to realize revenue from such wells until the inadequacy or unavailability is remedied. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. Our operators depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our General Partner and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Risks Related to the JOBS Act

We are an emerging growth company under the JOBS Act and we intend to take advantage of reduced disclosure and governance requirements applicable to emerging growth companies, which could result in our common units being less attractive to investors.

We are an emerging growth company, as defined in the JOBS Act, and we intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We cannot predict if investors will find our common units less attractive because we will rely on these exemptions. We expect to take advantage of these reporting exemptions until we are no longer an emerging growth company, which in certain circumstances could be for up to five years.

Our election to take advantage of the JOBS Act's extended accounting transition period may not make our financial statements easily comparable to other public companies.

Pursuant to the JOBS Act, as an emerging growth company we can elect to take advantage of the extended transition period for any new or revised accounting standards that may be issued by the Public Company Accounting Oversight Board or the SEC. We have elected to take advantage of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, we, as an emerging growth company, can adopt the standard for the private company. This may make comparison of our financial statements with any other public company that is neither an emerging growth company nor an emerging growth company that has opted out of using the extended transition period difficult or impossible as different or revised standards may be used. We cannot predict if investors will find our common units less attractive because we may rely on these exemptions.

The JOBS Act will allow us to postpone the date by which we must comply with certain laws and regulations intended to protect investors and reduce the amount of information provided in reports filed with the SEC.

The JOBS Act is intended to reduce the regulatory burden on emerging growth companies. We meet the definition of an emerging growth company and so long as we qualify as an emerging growth company we may, among other things:

be exempt from the provisions of Section 404(b) of the Sarbanes-Oxley Act requiring that our independent registered public accounting firm provide an attestation report on the effectiveness of its internal control over financial reporting;

- be exempt from the "say on pay" provisions (requiring a non-binding shareholder vote to approve compensation of certain executive officers) and the "say on golden parachute" provisions (requiring a non-binding shareholder vote to approve golden parachute arrangements for certain executive officers in connection with mergers and certain other business combinations) of the Dodd-Frank Act and certain disclosure requirements of the Dodd-Frank Act relating to compensation of our chief executive officer;
- be permitted to omit the detailed compensation discussion and analysis from proxy statements and reports filed under the Securities Exchange Act of 1934 and instead provide a reduced level of disclosure concerning executive compensation; and
- be exempt from any rules that may be adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report on the financial statements.

We currently intend to take advantage of all of the reduced regulatory and reporting requirements that will be available to us so long as we qualify as an emerging growth company.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes and not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service treats us as a corporation or we become subject to a material amount of entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and likely would pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and 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 such a tax on us by any state will reduce the cash available for distribution to a unitholder.

An IRS contest of our U.S. federal income tax positions may adversely affect the value for our common units, and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

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. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the value of our common units. In addition, costs incurred in any contest with the IRS will be borne indirectly by holders of common units and our General Partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Because holders of our common units will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

You may not qualify for percentage depletion deductions, and even if you do so qualify, you will be required to determine, and maintain records supporting, your deduction.

Percentage depletion is generally available with respect to common unitholders who qualify under the independent producer exemption contained in Code Section 613A(c). For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative products or the operation of a major refinery. We cannot determine whether or provide any assurance that you will qualify as an independent producer. Further, if you do qualify as an independent producer, you are required to determine the amount of your allowed percentage depletion deduction and maintain records supporting such determination.

We cannot assure you that we will meet the requirements for you to deduct intangible drilling and development costs.

Federal tax law places substantial limits on taxpayers' ability to deduct intangible drilling and development costs ("IDCs"). Generally speaking, an "operator" is permitted to elect to currently deduct, or capitalize and deduct ratably over a 60-month period, costs that are properly characterized as IDCs that the operator incurs in connection with the drilling and development of oil and natural gas wells. For purposes of deducting IDCs, an "operator" is generally defined as one that owns a working or an operating interest in an oil or gas well. If we determine that we are an "operator" with respect to our oil and gas wells, our determination is not binding on the IRS. The IRS may assert that we are not an "operator" with respect to one or more of our oil or gas wells at the time that IDCs are incurred. If the IRS were successful in such a challenge, we and, therefore, you, would not be entitled to deduct the IDCs incurred in connection with such wells.

If we are eligible to deduct IDCs, we cannot assure you that IDCs will be deductible in any given year.

If we are deemed to be an operator with respect to one or more of our oil or gas wells, our classification of a cost as an IDC is not binding on the IRS. The IRS may reclassify an item classified by us as an IDC as a cost that must be capitalized or that is not deductible.

The IRS could challenge the timing of our deductions of IDCs, which could result in an increase your tax liabilities.

IDCs are generally deductible when the well to which the costs relate is drilled. In some cases, IDCs may be paid in one year for a well that is not drilled until the following year. In those cases, the prepaid IDCs will not be deductible until the year when the well is drilled unless (i) drilling on the well to which the prepayment relates starts within 90 days after the end of the year the prepayment is made or (ii) it is reasonable to expect that the well will be fully drilled within 3 1/2 months of the prepayment. All of our wells may not be drilled during the year when we pay IDCs pursuant to a drilling contract. As a result, we could fail to satisfy the requirements to deduct the IDCs in the year when paid and/or the IRS may challenge the timing of our deduction of prepaid IDCs.

The deduction for IDCs may not be available to you if you do not have passive income.

If you invest in us, your share of our deduction for IDCs in the year you invest will be a passive loss that can be used to offset only passive income. Such deductions cannot be used to offset "active" income, such as salary and bonuses, or portfolio income, such as dividends and interest income. Any unused passive loss from IDCs may be carried forward indefinitely by you to offset your passive income in subsequent taxable years. Certain taxpayers are not subject to the passive loss rules.

On the disposition of property by us or of common units by you, certain deductions for IDCs, depletion, and depreciation must be recaptured as ordinary income.

You may be required to recapture as ordinary income certain deductions for IDCs, depletion, and depreciation on disposition of property by us or on disposition of our common units.

We cannot assure you whether the deduction related to U.S. production activities will be available to a particular common unitholder or the extent of any such deduction to any particular common unitholder.

The Code Section 199 deduction is required to be computed separately by each common unitholder. Consequently, no assurance can be given, and counsel is unable to express any opinion, as to the availability or extent of the Code

Section 199 deduction to any particular common unitholder. We encourage you to consult your tax advisor to determine whether the Code Section 199 deduction would be available to you.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that unit, even if the price is less than your original cost. As discussed above, a substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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, such as individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. For example, much of our income allocated to organizations that are exempt from federal income tax, including IRAs, will be unrelated business taxable income and will be taxable to them. Similarly, much of our income allocable to non-U.S. persons will constitute effectively connected U.S. trade or business income, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable 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 the partnership for U.S. federal income tax purposes.

We will be considered to have terminated 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 example, an exchange of 50% of our capital and profits could occur if, in any twelve-month period, holders of our common units sell at least 50% of the interests in our capital and profits. Our termination would, among other things, result in the closing of our taxable year for all holders of common units and could result in a deferral of certain deductions allowable in computing our taxable income.

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

In addition to federal income taxes, you will likely be subject to other taxes, including state and local 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, even if you do not live in any of those jurisdictions. You 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 jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements.

Certain 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.

From time to time, legislation has been introduced that would enact tax changes that may repeal tax incentives and deductions that are currently used by U.S. oil and gas companies. The passage of any legislation with changes in U.S. federal income tax laws could increase the amount of our taxable income allocable to you. We are unable to predict whether any changes, or other proposals, will ultimately be enacted. Any modifications to the federal income tax laws or interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

Information regarding the Partnership's properties is contained in "Item 1. Business", "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources: Oil and Gas Properties", and "Item 8. Financial Statements and Supplementary Data – Note 3. Oil and Gas Investments" contained herein.

Item 3. Legal Proceedings

At the end of the period covered by this Annual Report on Form 10-K, the Partnership was not a party to any material, pending legal proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

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

Common Units

The Partnership's Registration Statement on Form S-1 (File No. 333-197476) was declared effective by the Securities and Exchange Commission on January 22, 2015. Under the public offering we are making under the Registration Statement (as amended and supplemented), we are offering common units of limited partner interest (the "common units") on a best-efforts basis with the maximum offering up to $2,000,000,000 of capital, consisting of 100,263,158 common units. As of December 31, 2016, the Partnership had completed the sale of 14,582,963 common units for total gross proceeds of $286.4 million and proceeds net of offering costs, including selling commissions and marketing expenses, of $267.1 million. As of December 31, 2016, 85,680,195 common units remained unsold. As of March 3, 2017 the common units were held by approximately 4,300 unitholders. The offering will expire on April 24, 2017, provided that the offering will be terminated if all of the common units are sold before then. The public offering is being made through David Lerner Associates, Inc. (the "Dealer Manager") and is continuing at $20.00 per unit.

Upon formation of the Partnership, the General Partner and organizational limited partner made initial capital contributions totaling $1,000 to the Partnership. Upon closing of the minimum offering in August 2015, the organizational limited partner withdrew its initial capital contribution of $990, the General Partner received Incentive Distribution Rights (defined below), and has been and will continue to be reimbursed for its documented third-party out-of-pocket expenses incurred in organizing the Partnership and offering the common units. Under our agreement with the Dealer Manager, the Dealer Manager receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership. Based on the common units sold through December 31, 2016, the total contingent fee is approximately $11.5 million.

There is currently no established public trading market in which the Partnership's common units are traded. The net proceeds of the public offering were used as follows:

Use of Proceeds

The following tables set forth information concerning the ongoing best-efforts offering and the use of proceeds from the offering as of December 31, 2016.

Units Registered						
	5,263,158	Units	$	19.00	per unit	$ 100,000,002
	95,000,000	Units	$	20.00	per unit	1,900,000,000
Totals:	100,263,158	Units				$ 2,000,000,002
Units Sold						
	5,263,158	Units	$	19.00	per unit	$ 100,000,002
	9,319,805	Units	$	20.00	per unit	186,396,100
Totals:	14,582,963	Units				$ 286,396,102

Expenses of Issuance and Distribution of Units	
1. Underwriting commissions	$ 17,183,766
2. Expenses of underwriters	-
3. Direct or indirect payments to directors or officers of the Partnership or their associates, or to affiliates of the Partnership	-
4. Fees and expenses of third parties	2,105,542
Total Expenses of Issuance and Distribution of Common Shares	19,289,308
Net Proceeds to the Partnership	$ 267,106,794
1. Purchase of oil, gas and natural gas liquids properties (net of debt, proceeds and repayment including interest and acquisition costs)	$ 165,199,443
2. Deposits and other costs associated with potential oil, natural gas and natural gas liquids acquisitions	10,000,000
3. Repayment of other indebtedness, including interest expense paid	-
4. Investment and working capital	81,458,370
5. Fees and expenses of third parties	-
6. Other	-
7. Distributions	10,448,981
Total Application of Net Proceeds to the Partnership	$ 267,106,794

Class B Units

Upon entering into the management agreement with the Former Manager on August 19, 2015, the Partnership issued 100,000 Class B units to Incentive Holdings, an affiliate of the Former Manager. Upon the termination of the Management Agreement and in accordance with the terms therewith, 37.5% of the Class B units owned by Incentive Holdings were canceled. As of December 31, 2016, the outstanding Class B units totaled 62,500. The Partnership may issue up to 37,500 Class B units, the amount cancelled in conjunction with the termination of the Management Agreement. The Class B units provide for certain distribution rights described below.

Distribution Policy

Prior to "Payout," which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights or with respect to Class B units and will not make the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership's assets, will be made as follows:

First, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) to the Dealer Manager, as the contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any, to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest.

All items of income, gain, loss and deduction will be allocated to each Partner's capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2016, the Partnership paid distributions of $1.40 per common unit or $10.4 million, and for the year ended December 31, 2015, the Partnership paid distributions of $0.51 per common unit or $1.3 million. The Partnership began paying distributions upon reaching the minimum offering in August 2015.

Neither the Partnership nor the General Partner has adopted an equity compensation plan.

Item 6. Selected Financial Data

Not applicable.

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

Overview

The Partnership was formed as a Delaware limited partnership. The General Partner is Energy 11 GP, LLC (the "General Partner"). The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership is offering common units of limited partner interest (the "common units") on a best-efforts basis, with the maximum offering up to $2,000,000,000 of capital, consisting of 100,263,158 common units. The Partnership's Registration Statement on Form S-1 (File No. 333-197476) was declared effective by the SEC on January 22, 2015. As of August 19, 2015, the Partnership completed the sale of the minimum offering of 1,315,790 common units for gross proceeds of $25 million. Upon raising the minimum offering amount, the holders of the common units were admitted and the Partnership commenced operations. Through December 31, 2016, the Partnership had sold a total of 14,582,963 common units for gross proceeds of $286.4 million.

The Partnership has no officers, directors or employees. Instead, the General Partner manages the day to day affairs of the Partnership. All decisions regarding the management of the Partnership made by the General Partner are made by the Board of Directors of the General Partner and its officers.

The Partnership was formed to acquire and develop oil and gas properties located onshore in the United States. The Partnership will seek to acquire working interests, leasehold interests, royalty interests, overriding royalty interests, production payments and other interests in producing and nonproducing oil and gas properties. On December 18, 2015, the Partnership completed its purchase of an approximate 11% working interest in approximately 215 existing producing wells and approximately 262 future development locations in the Sanish field located in Mountrail County, North Dakota (the "Sanish Field Assets"). The Sanish Field Assets are a part of the Bakken shale formation in the Greater Williston Basin.

As of December 31, 2016, the Partnership had 216 producing wells, with approximately 257 future development locations. The Partnership's assets owned at December 31, 2016 are non-operated oil and gas wells, substantially all of which are managed and operated by Whiting Petroleum Company ("Whiting"). Whiting, a publicly traded oil and gas company, operates the assets on behalf of the Partnership and other working interest owners.

On January 11, 2017, the Partnership completed the purchase of an additional 11% working interest in the Sanish Field Assets. The purchase price was $130.0 million and was funded by the Partnership with $90.0 million in cash (from the sale of the Partnership's common units in its ongoing, best-efforts offering) and a $40.0 million promissory note ("Seller Note"). The Partnership paid the $40.0 million Seller Note in full on February 23, 2017. The Seller Note bore interest at 5% per annum up to the payoff date.

Current Price Environment

Oil, natural gas and natural gas liquids ("NGL") prices are determined by many factors outside of the Partnership's control. Historically, energy commodity prices have been volatile; oil prices declined throughout 2015 and in the first quarter of 2016, prices had fallen to the lowest levels since October 2003. Commodity prices increased to 52-week highs by December 2016, but due to geopolitical risks in oil-producing regions of the world as well as global supply and demand concerns, the Partnership continues to expect significant price volatility. In addition to commodity price fluctuations, the Partnership faces the challenge of natural production volume declines. As reservoirs are depleted, oil and natural gas production from Partnership wells will decrease.

The following table lists average NYMEX prices for oil and natural gas for the years ended December 31, 2016 and 2015.

	Year (Period) Ended December 31,	
	2016	**2015**
Average market closing prices [(1)]		
Oil (per Bbl)	$ 43.40	$ 48.79
Natural gas (per Mcf)	$ 2.52	$ 2.62

(1) Based on average NYMEX futures closing prices (oil) and NYMEX/Henry Hub spot prices (natural gas)

Partnership revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. Future growth is dependent on the Partnership's ability to add reserves in excess of production. Dependent on available cash flow, the Partnership intends to seek opportunities to invest in its existing production wells, drill new wells on existing leasehold sites and/or acquire additional reserves.

As specified by the SEC, the prices for oil, natural gas and NGL used to calculate Partnership reserves were the average prices during the 2016 calendar year, with the average determined using the price on the first day of each month. The prices, before price differentials, utilized in calculating total estimated proved reserves at December 31, 2016 were $42.75 per barrel of oil and $2.48 per thousand cubic feet (Mcf) of natural gas. The prices, after price differentials, were $36.25 per barrel of oil, ($0.38) per Mcf of natural gas and $4.70 per barrel of NGL.

Results of Operations for Years 2016 and 2015

The Partnership closed on the purchase of the Sanish Field Assets on December 18, 2015. Because the Partnership only had 14 days of revenues and operating expenses in 2015, the operating results between the years ended December 31, 2016 and 2015 is not comparable, except as otherwise indicated below.

	Year (Period) Ended December 31, 2016	Year (Period) Ended December 31, 2015 (1)
Production (BOE):		
Oil	498,926	21,937
Natural gas	86,521	3,065
Natural gas liquids	69,059	2,841
Total	654,506	27,843
Average sales price per unit:		
Oil (per Bbl)	$ 36.50	$ 30.17
Natural gas (per Mcf)	2.43	1.47
Natural gas liquids (per Bbl)	12.97	5.29
Combined (per BOE)	31.12	25.28
Average unit cost per BOE:		
Production costs:		
Lease operating expenses	$ 5.81	$ 5.35
Gathering and processing expenses	2.66	0.60
Workover expenses	0.41	0.05
Production taxes	2.86	2.67
Total production costs	11.74	8.67
Depreciation, depletion and amortization	14.56	14.07

(1) All production and cost figures are derived from the Partnership's ownership of the properties from December 18, 2015 through December 31, 2015.

Oil, Natural Gas and NGL Sales

For the years ended December 31, 2016 and 2015, revenues for oil, natural gas and NGL sales were $20.4 million and $0.7 million, respectively. Revenues for the sale of crude oil were $18.2 million and $0.7 million, which resulted in realized prices of $36.50 and $30.17 per barrel, respectively. Revenues for the sale of natural gas were $1.3 million and $27,000, which resulted in realized prices of $2.43 and $1.47 per MCF, respectively. Revenues for the sale of NGL were $0.9 million and $15,037, which resulted in realized prices of $12.97 and $5.29 per barrel of oil equivalent ("BOE") of production, respectively. As noted above, market prices for each of these products increased throughout the year, with average realized prices in the fourth quarter of 2016 totaling approximately $42.61 per barrel for oil, $3.27 per Mcf for natural gas and $16.33 per BOE for NGL.

For the years ended December 31, 2016 and 2015, the Partnership's working interest production volumes totaled 654,506 and 27,843 BOE units, respectively. The oil, natural gas and NGL production resulted from the Partnership's working interest in producing properties in the Sanish Field in North Dakota and the associated horizontal wells on that leasehold. Production in 2017 will be dependent on the investment in existing wells and the development of new wells. If the Partnership or our operator is unable or it is not cost beneficial to invest in existing wells or develop new wells, production will decline.

Operating Costs and Expenses

Lease Operating Expenses ("LOE")

For the years ended December 31, 2016 and 2015, LOE was $3.8 million and $149,072, respectively, and LOE per BOE of production were $5.81 and $5.35, respectively. While monthly LOE has stabilized during 2016, production has decreased over the same period, which directly led to an increase in LOE per BOE of production throughout the year. LOE for the fourth quarter of 2016 was $6.73 per BOE of production.

Gathering and Processing Expenses

For the years ended December 31, 2016 and 2015, gathering and processing fees were $1.7 million and $16,689, respectively. Gathering and processing costs per BOE of production were $2.66 and $0.60, respectively. During the third quarter of 2016, the Partnership's operator amended its gathering and processing contract, which led to increases in gathering and processing costs. Higher third-party fractionation expenses also contributed to the significant increase in gathering and processing costs, in total and per BOE of production, during the second half of 2016. Costs in the fourth quarter of 2016 were $3.36 per BOE of production.

From time to time, expenses will be incurred on a producing well to restore or increase production. For the years ended December 31, 2016 and 2015, workover expenses were $0.3 million and $1,450, respectively. Workover expenses per BOE of production were $0.41 and $0.05, respectively. The Partnership authorized substantial rework on two wells during 2016, leading to the increase in workover expenses per BOE of production. These costs will vary depending on the need for specific well rework. Costs in the fourth quarter of 2016 were $0.57 per BOE of production.

Production Taxes

North Dakota's oil tax structure is comprised of two main taxes: the production tax and the extraction tax. The production tax is 5% of gross revenue. Beginning January 1, 2016, the extraction tax rate is also 5% of the gross value at the well. This rate can increase to 6% if the high-price trigger, defined as the average price of a barrel of oil exceeding a trigger price of $90 for each month in any consecutive three-month period, is in effect. The 6% rate would remain in effect until the average price is less than $90 per barrel for each month in any consecutive three-month period.

The production tax on gas is subject to a price index change on July 1 of each calendar year. The rate for July 1, 2016 through June 30, 2017 is $0.0601 per Mcf. The previous rate from July 1, 2015 through June 30, 2016 was $0.1106 per Mcf.

Production taxes for the years ended December 31, 2016 and 2015 were $1.9 million and $74,460, respectively. Production taxes per BOE of production were $2.86 and $2.67, respectively. Production taxes in the fourth quarter of 2016 were $3.24 per BOE of production.

Depreciation, Depletion and Amortization ("DD&A")

DD&A of capitalized drilling and development costs of producing oil, natural gas and NGL properties are computed using the unit-of-production method on a field basis based on total estimated proved developed oil, natural gas and NGL reserves. Costs of acquiring proved properties are depleted using the unit-of-production method on a field basis based on total estimated proved developed and undeveloped reserves. DD&A for the years ended December 31, 2016 and 2015 was $9.5 million and $0.4 million, and DD&A per BOE of production was $14.56 and $14.07, respectively.

Management Fees

Fees and expenses incurred under the Management Agreement with the Former Manager for the years ended December 31, 2016 and 2015 were $0.9 million and $0.5 million. As discussed below, the Management Agreement was terminated in April 2016. The reduction in management fees is partially offset by the Partnership utilizing additional external resources to replace certain services previously provided by the Former Manager. Therefore, the Partnership has increased accounting and consulting fees, which are classified as general and administrative costs.

Acquisition Costs

Costs related to the acquisition of the Sanish Field Assets for the years ended December 31, 2016 and 2015 were $0.1 million and $0.3 million. These costs include legal, accounting and due diligence associated with the 2017 and 2015 purchases of the Partnership's working interests in the Sanish Field Assets.

General and Administrative Costs

General and administrative costs for the years ended December 31, 2016 and 2015 were $1.3 million and $0.7 million, respectively. The principal components of general and administrative expense are accounting, legal and consulting fees. General and administrative expenses for the twelve months ended December 31, 2016 exceeded those of the prior year due to a full year of operations following the closing of the Partnership's interest in the Sanish Field Assets in December 2015 as well as the Management Agreement that was terminated in April 2016.

Interest Expense

Interest expense, net, for the years ended December 31, 2016 and 2015 was $6.1 million and $0.3 million, respectively. The increase in interest expense, net, during 2016 as compared to 2015 was primarily due to (a) nine months of interest expense on the $97.5 million Seller Note related to the Partnership's initial 2015 acquisition of its interest in the Sanish Field Assets (Seller Note paid in full in September 2016), (b) nine months of amortization of the mark-to-market adjustment on the $97.5 million Seller Note; (c) amortization of deferred origination costs on the $97.5 million Seller Note; and (d) accretion of the Partnership's deferred purchase price and contingent consideration liabilities incurred with the 2015 acquisition.

Management Agreement

At the initial closing of the sale of common units on August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with E11 Management LLC (the "Former Manager") to provide management and operating services regarding substantially all aspects of the Partnership. Under the Management Agreement, the Former Manager agreed to provide management and operating services to the Partnership in exchange for a monthly fee. In addition, the Partnership issued 100,000 Class B units to an affiliate of the Former Manager upon entering into the Management Agreement. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Distributions below.

The Former Manager was formed by Aubrey K. McClendon. The Management Agreement was terminable by the Partnership if, among other reasons, Mr. McClendon, the Former Manager's key employee, ceased to be employed by the Former Manager and the Partnership did not approve of a proposed replacement of such key employee. On March 2, 2016, Mr. McClendon died in a car accident. Following Mr. McClendon's death and subsequent correspondence between the Former Manager and the Partnership, on April 5, 2016, the Partnership elected not to approve a replacement key employee for Mr. McClendon and exercised its right to terminate the Management Agreement. Accordingly, the fees under the Management Agreement were no longer accrued as of the effective date of termination. Also, upon termination of the Management Agreement and in accordance with the terms therewith, 37.5% of the Class B units owned by Incentive Holdings were canceled. As of December 31, 2016, the Class B units owned by Incentive Holdings totaled 62,500.

Since substantially all the Partnership's properties are operated by Whiting and the Partnership only owns a non-operating working interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting. Consequently, the termination of the Management Agreement has not had and the Partnership does not anticipate that the termination will have an adverse effect on its operations.

Prior to termination, the Partnership incurred fees and reimbursable costs of approximately $0.9 million and $0.5 million, for the years ended December 31, 2016 and 2015, respectively, under the Management Agreement.

Supplemental Non-GAAP Measure

The Partnership uses "EBITDAX", defined as Earnings before Interest, Income Taxes, Depreciation, Depletion, Amortization and Exploration Expenses, as a key supplemental measure of its operating performance. This non-GAAP financial measure should be considered along with, but not as alternatives to, net income (loss), operating income (loss), cash flow from operating activities or other measures of financial performance presented in accordance with GAAP. EBITDAX is not necessarily indicative of funds available to fund the Company's cash needs, including its ability to make cash distributions. Although EBITDAX, as calculated by the Partnership, may not be comparable to EBITDAX as reported by other companies that do not define such terms exactly as the Partnership defines such terms, the Partnership believes this supplemental measure is useful to investors when comparing the Partnership's results between periods and with other energy companies.

The Partnership believes that the presentation of EBITDAX is important to provide investors with additional information (i) to provide an important supplemental indicator of the operational performance of the Partnership's business without regard to financing methods and capital structure, and (ii) to measure the operational performance of the Partnership's operator.

The following table reconciles the Partnership's GAAP net loss to EBITDAX for the years ended December 31, 2016 and 2015.

	Years ended December 31,	
	2016	**2015**
Net loss	$ (5,230,564)	$ (1,562,816)
Interest expense, net	6,132,805	321,093
Depreciation, depletion and amortization	9,526,865	392,084
Exploration expenses	-	-
EBITDAX	$ 10,429,106	$ (849,639)

Liquidity and Capital Resources

The Partnership's principal source of liquidity will be the proceeds of the best-efforts offering until it expires in April 2017, cash on hand, and the cash flow generated from properties the Partnership has acquired. In addition, the Partnership may borrow funds to pay operating expenses, distributions, make acquisitions or for other capital needs of the Partnership. In September 2016, the Partnership repaid the Seller Note that was entered into in conjunction with the initial purchase of the Sanish Field Assets.

The Partnership anticipates that cash on hand, cash flow from operations and proceeds of the best-efforts offering will be adequate to meet its anticipated liquidity requirements for at least the next 12 months, including the acquisition of the additional approximate 11% working interest in the Sanish Field Assets for a purchase price of $130.0 million, as discussed above.

Partners Equity

The Partnership intends to continue to raise capital through its best-efforts offering of common units by David Lerner Associates, Inc. (the "Dealer Manager") through its expiration in April 2017. The Dealer Manager receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager may also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership.

As of August 19, 2015, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. In March 2016, the Partnership completed the sale of 5,263,158 common units at $19.00 per common unit. All subsequent shares of common units are being sold at $20.00 per common unit. As of December 31, 2016, the Partnership had completed the sale of 14,582,963 common units for total gross proceeds of $286.4 million and proceeds net of offering costs including selling commissions and marketing expenses of $267.1 million. As of December 31, 2016, 85,680,195 common units remained unsold. The Partnership has extended its offering through April 24, 2017, provided that the offering will be terminated if all of the common units are sold before then.

Distributions

Prior to “Payout,” which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights (owned by the General Partner), with respect to Class B units or the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines “Payout Accrual” as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership’s assets, will be made as follows:

First, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) to the Dealer Manager, as the contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any, to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest.

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed above.

For the year ended December 31, 2016, the Partnership made distributions of $1.40 per common unit, or $10.4 million, and generated approximately $6.9 million in cash from operations.

Since a portion of distributions to date have been funded with proceeds from the offering of common units, the Partnership’s ability to maintain its current rate of distribution ($1.40 per unit per year) will be based on its ability to increase its cash generated from operations. As there can be no assurance that the Partnership’s current assets will or that the Partnership can acquire additional properties that provide income at this level, there can be no assurance as to the classification or duration of distributions at the current rate. Proceeds of the offering which are distributed are not available for investment in properties.

Financing

As part of the financing for the initial purchase of an approximate 11% non-operated working interest in the Sanish Field Assets, on December 18, 2015, the Partnership executed a note in favor of the sellers in the original principal amount of $97.5 million. On September 29, 2016, the Partnership paid the Seller Note in full.

As discussed above, the Partnership entered into a new Seller Note in January 2017 with the purchase of the additional approximate 11% working interest in the Sanish Field Assets. The Partnership paid off the new Seller Note on February 23, 2017 using a significant portion of equity proceeds raised in 2017.

Oil and Gas Properties

The Partnership incurred approximately $1.7 million in capital expenditures for the year ended December 31, 2016 and expects to invest approximately $10.0 to $15.0 million in capital expenditures during 2017, which includes drilling and completion of approximately five to ten new wells. If oil, natural gas and NGL prices during 2017 are not at levels that make it cost beneficial to drill and complete new wells, the Partnership expects to invest approximately $1.5 to $3.0 million in capital expenditures in 2017. However, the capital expenditure plan has the flexibility to adjust should the commodity price environment change. A decrease in oil, natural gas and NGL prices will lead to a reduction in capital expenditures and lower oil, NGL and natural gas production volumes.

Since the Partnership is not the operator of any of its oil and natural gas properties, it is difficult to predict levels of future participation in the drilling and completion of new wells and their associated capital expenditures. This makes capital expenditures for drilling and completion projects difficult to forecast for 2017 and current estimated capital expenditures could be significantly different from amounts actually invested.

The Partnership expects to fund overhead costs and capital additions related to the drilling and completion of wells primarily from cash provided by operating activities and cash on hand.

Transactions with Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to existing related party transactions, as well as any new significant related party transactions.

See further discussion in Note 8 titled "Related Parties" in Part II, Item 8 of this Form 10-K and in Part III, Item 13 — "*Certain Relationships and Related Transactions, and Director Independence*" below.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosures about contingent assets and liabilities. Certain of our accounting policies involve estimates and assumptions 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 base these estimates and assumptions on historical experience and on various other information and assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as additional information is obtained, as more experience is acquired, as our operating environment changes and as new events occur.

Our critical accounting policies are important to the portrayal of both our financial condition and results of operations and require us to make difficult, subjective or complex assumptions or estimates about matters that are uncertain. We would report different amounts in our consolidated financial statements, which could be material, if we used different assumptions or estimates. We believe that the following are the critical accounting policies used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

No gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred.

Impairment

We assess our proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, we recognize an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management’s outlook of future commodity prices. The underlying commodity prices used in the determination of our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Estimates of Oil, Natural Gas and Natural Gas Liquids Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids 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 estimate. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production, both of which provide accurate forecasts. Non–producing reserve estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods. These methods provide accurate forecasts due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Independent reserve engineers prepare our reserve estimates at the end of each year.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units–of–production method to amortize the costs of our oil and natural gas properties, the quantity of reserves could significantly impact our depreciation, depletion and amortization expense. Our reserves are also the basis of our supplemental oil and natural gas disclosures.

Accounting for Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

We record an asset retirement obligation (“ARO”) and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

Inherent in the present value calculation 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 of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of our contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

The Partnership does not operate its oil and natural gas properties and, therefore, receives actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well are used to estimate the accrual of revenue on these wells. The oil, natural gas and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, natural gas and NGLs. These variables could lead to an over or under accrual of oil, natural gas and NGL sales at the end of any particular quarter. However, the Partnership adjusts the estimated accruals of revenue to actual production in the period actual production is determined.

Recent Accounting Standards

See Note 2. Summary of Significant Accounting Policies in the footnotes to our financial statements for a summary of recent accounting standards.

Subsequent Events

On January 11, 2017, the Partnership closed on the purchase of all of the issued and outstanding limited liability company interests of Kaiser-Whiting, LLC, which represents an additional approximate 11% non-operated working interest in the Sanish Field Assets. The purchase price of $130.0 million, subject to customary adjustments, consisted of cash payments totaling $90.0 million and the delivery of a promissory note in favor of the seller of $40.0 million. The Partnership paid the $40.0 million promissory note in full on February 23, 2017. With the closing of the purchase, the Partnership now owns an approximate 22-23% non-operated working interest in the Sanish Field Assets. See further discussion in Note 3. Oil and Gas Investments in the footnotes to our financial statements.

In January 2017, the Partnership declared and paid $1.6 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In January 2017, the Partnership closed on the issuance of approximately 1.1 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $21.7 million and proceeds net of selling and marketing costs of approximately $20.4 million.

In February 2017, the Partnership declared and paid $1.7 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In February 2017, the Partnership closed on the issuance of approximately 1.0 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $20.4 million and proceeds net of selling and marketing costs of approximately $19.2 million.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Not Applicable.

Item 8. Financial Statements and Supplementary Data

Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner
Energy 11, L.P.

We have audited the accompanying consolidated balance sheets of Energy 11, L.P. (a Delaware limited partnership) and its subsidiaries (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of operations, partners' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these 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. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Energy 11, L.P. and its subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/S/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 3, 2017

Energy 11, L.P.
Consolidated Balance Sheets

	December 31, 2016	December 31, 2015
Assets		
Cash and cash equivalents	$ 86,800,596	$ 3,287,054
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	2,718,296	1,417,751
Acquisition post-closing receivable	-	1,556,530
Other current assets	10,038,221	-
Total Current Assets	99,557,113	6,261,335
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization; December 31, 2016, $9,908,800; December 31, 2015, $391,624	151,554,972	158,895,191
Total Assets	$ 251,112,085	$ 165,156,526
Liabilities and Partners' Equity		
Note payable	$ -	$ 81,684,758
Contingent consideration	-	4,743,752
Accounts payable and accrued expenses	2,693,023	3,449,442
Total Current Liabilities	2,693,023	89,877,952
Limited partners' interest (14,582,963 common units and 4,486,625 common units issued and outstanding at December 31, 2016 and December 31, 2015, respectively)	248,420,789	75,280,301
General partners' interest	(1,727)	(1,727)
Class B units (62,500 and 100,000 units issued and outstanding at December 31, 2016 and December 31, 2015, respectively)	-	-
Total Partners' Equity	248,419,062	75,278,574
Total Liabilities and Partners' Equity	$ 251,112,085	$ 165,156,526

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Operations

	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenue			
Oil, natural gas and natural gas liquids revenues	$ 20,365,338	$ 703,806	$ -
Operating costs and expenses			
Lease operating expenses	3,801,312	149,072	-
Gathering and processing expenses	2,009,799	18,139	-
Production taxes	1,870,212	74,460	-
Management fees	886,306	252,524	-
Acquisition related costs	77,550	313,366	-
General and administrative expenses	1,291,053	745,884	163,595
Depreciation, depletion and amortization	9,526,865	392,084	-
Total operating costs and expenses	19,463,097	1,945,529	163,595
Operating income (loss)	902,241	(1,241,723)	(163,595)
Interest expense, net	(6,132,805)	(321,093)	-
Net loss	$ (5,230,564)	$ (1,562,816)	$ (163,595)
Basic and diluted net loss per common unit	$ (0.69)	$ (1.70)	$ -
Weighted average common units outstanding - basic and diluted	7,538,180	920,668	-

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Partners' Equity (Deficit)

	Limited Partner Amount	Class B Units Amount	General Partner Amount	Total Partners' Equity/(Deficit)
Balance December 31, 2013	$ (8,965)	$ -	$ (91)	$ (9,056)
2014 Net Loss	(161,959)	-	(1,636)	(163,595)
Balance December 31, 2014	(170,924)	-	(1,727)	(172,651)
Net proceeds from issuance of common units	78,286,761	-	-	78,286,761
Distributions to organizational limited partner	(990)	-	-	(990)
Distributions declared and paid to common units ($0.510138 per unit)	(1,271,730)	-	-	(1,271,730)
2015 Net Loss	(1,562,816)	-	-	(1,562,816)
Balance December 31, 2015	75,280,301	-	(1,727)	75,278,574
Net proceeds from issuance of common units	188,820,033	-	-	188,820,033
Distributions declared and paid to common units ($1.400000 per unit)	(10,448,981)	-	-	(10,448,981)
2016 Net Loss	(5,230,564)	-	-	(5,230,564)
Balance December 31, 2016	$ 248,420,789	$ -	$ (1,727)	$ 248,419,062

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Cash Flows

	For the Year Ended December 31, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
Cash flow from operating activities:			
Net loss	$ (5,230,564)	$ (1,562,816)	$ (163,595)
Adjustments to reconcile net loss to cash from operating activities:			
Depreciation, depletion and amortization	9,526,865	392,084	-
Non-cash expenses, net	4,017,238	175,424	-
Changes in operating assets and liabilities:			
Accounts receivable oil, natural gas and natural gas liquids revenues	(2,004,351)	(703,806)	-
Other current assets	(38,221)	-	-
Accounts payable and accrued expenses	678,417	653,106	-
Due to general partner member	-	(158,641)	163,595
Net cash flow provided by (used in) operating activities	6,949,384	(1,204,649)	-
Cash flow from investing activities:			
Cash paid for acquisition of oil, natural gas and natural gas liquids properties	(1,000,000)	(60,000,000)	-
Deposit for potential acquisition	(10,000,000)	-	-
Additions to oil and natural gas properties	(1,644,186)	-	-
Net cash flow used in investing activities	(12,644,186)	(60,000,000)	-
Cash flow from financing activities:			
Cash paid for deferred loan costs	(250,000)	-	-
Net proceeds related to issuance of units	188,825,158	78,308,749	-
Distributions paid to limited partners	(10,448,981)	(1,271,730)	-
Payments on note payable	(88,917,833)	(12,545,410)	-
Net cash flow provided by financing activities	89,208,344	64,491,609	-
Increase in cash and cash equivalents	83,513,542	3,286,960	-
Cash and cash equivalents, beginning of period	3,287,054	94	94
Cash and cash equivalents, end of period	$ 86,800,596	$ 3,287,054	$ 94
Interest paid	$ 2,171,573	$ 173,711	$ -
Supplemental non-cash information:			
Increase in note payable, payment of contingent consideration	5,000,000	-	-
Decrease in note payable, settlement of pre-close activity	1,082,167	-	-
Note payable assumed in acquisition	-	97,545,410	-
Contingent consideration in acquisition	-	4,725,448	-
Deferred purchase price of acquisition	-	1,702,203	-
Accounts receivable from seller in acquisition, net of assumed payables	-	1,395,883	-
Accrued deferred offering costs and other assets	-	-	1,181,442

See notes to consolidated financial statements.

Energy 11, L.P.
Notes to Consolidated Financial Statements

Note 1. Partnership Organization

Energy 11, L.P. (together with its wholly-owned subsidiaries, the "Partnership") was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership is offering common units of limited partner interest (the "common units") on a best-efforts basis with the maximum offering up to $2,000,000,000 of capital, consisting of 100,263,158 common units. The Partnership's offering was declared effective by the Securities and Exchange Commission ("SEC") on January 22, 2015. As of August 19, 2015, the Partnership completed the sale of the minimum offering of 1,315,790 common units. The subscribers were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time.

The Partnership's primary investment objectives are to (i) acquire producing and non-producing oil and gas properties with development potential, and to enhance the value of the properties through drilling and other development activities, (ii) make distributions to the holders of the common units, (iii) engage in a liquidity transaction after five – seven years, in which all properties are sold and the sales proceeds are distributed to the partners, merge with another entity, or list the common units on a national securities exchange, and (iv) permit holders of common units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the common units primarily have been and will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties.

The General Partner of the Partnership is Energy 11 GP, LLC (the "General Partner"). The General Partner manages and controls the business affairs of the Partnership. David Lerner Associates, Inc. (the "Dealer Manager") is the dealer manager for the offering of the common units.

The Partnership's fiscal year ends on December 31.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Partnership have been prepared in accordance with United States generally accepted accounting principles ("US GAAP").

Cash and Cash Equivalents

Cash and cash equivalents consist of highly liquid investments with original maturities of three months or less. The fair market value of cash and cash equivalents approximates their carrying value. Cash balances may at times exceed federal depository insurance limits.

Offering Costs

The Partnership is raising capital through an ongoing best-efforts offering of common units by David Lerner Associates, Inc., who receives a selling commission and a marketing expense allowance based on proceeds of the common units sold. Additionally, the Partnership has incurred other offering costs including legal, accounting and reporting services. These offering costs are recorded by the Partnership as a reduction of partners' equity. As of December 31, 2016 and 2015, the Partnership had sold 14.6 million and 4.5 million common units for gross proceeds of $286.4 million and $85.2 million, respectively, and proceeds net of offering costs of $267.1 million and $78.3 million, respectively.

Property and Depreciation, Depletion and Amortization

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

No gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Impairment

We assess our proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, we recognize an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management’s outlook of future commodity prices. Where probable and possible reserves exist, an appropriately risk adjusted amount of these reserves is included in the impairment evaluation. The underlying commodity prices used in the determination of our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Partnership’s accounts receivable are due from purchasers of oil, natural gas and NGLs or operators of the oil and natural gas properties. Oil, natural gas and NGL sales receivables are generally unsecured. This industry concentration has the potential to impact the Partnership’s overall exposure to credit risk, in that the purchasers of the Partnership’s oil, natural gas and NGLs and the operators of the properties we have an interest in may be similarly affected by changes in economic, industry or other conditions. At December 31, 2016, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2016, the Partnership’s oil, natural gas and NGL sales were through two operators. Whiting Petroleum Corporation (“Whiting”) is the operator of 99% the Partnership’s properties. All oil and natural gas producing activities of the Partnership are in North Dakota and represent substantially all of the business activities of the Partnership.

Asset Retirement Obligation

We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

We record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

Inherent in the present value calculation 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 of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

The following table shows the activity for the years ended December 31, 2016 and 2015, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2014	$	-
Liabilities acquired on December 18, 2015 (acquisition)		105,000
Accretion (December 18, 2015 to December 31, 2015)		459
Balance as of December 31, 2015		105,459
Well additions		1,868
Accretion		9,689
Revisions in estimated cash flows		(46,393)
Balance as of December 31, 2016	$	70,623

Income Tax

The Partnership is taxed as a partnership for federal and state income tax purposes. No provision for income taxes has been recorded since the liability for such taxes is that of each of the partners rather than the Partnership. The Partnership's income tax returns are subject to examination by the federal and state taxing authorities, and changes, if any, could adjust the individual income tax of the partners.

The Partnership has evaluated whether any material tax position taken will more likely than not be sustained upon examination by the appropriate taxing authority and believes that all such material tax positions taken are supportable by existing laws and related interpretations.

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production.

Environmental Costs

As the Partnership is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays. The Partnership does not believe the existence of current environmental laws or interpretations thereof will materially hinder or adversely affect the Partnership's business operations; however, there can be no assurances of future effects on the Partnership of new laws or interpretations thereof. Since the Partnership does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with the Partnership being responsible for its proportionate share of the costs involved.

Environmental liabilities are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At December 31, 2016 and 2015, there were no such costs accrued.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of crude oil, natural gas and NGL reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as depreciation, depletion and amortization (“DD&A”) and impairment calculations. On an annual basis, the Partnership’s independent consulting petroleum engineer, with assistance from the Partnership, prepares estimates of crude oil, natural gas and NGL reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the reserve estimates were based on average individual product prices during the 12-month period prior to December 31, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period excluding escalations based upon future conditions. For impairment purposes, projected NYMEX forward strip prices for crude oil, natural gas and NGL as estimated by management are used. Crude oil, natural gas and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future crude oil, natural gas and NGL pricing assumptions are used by management to prepare estimates of crude oil, natural gas and NGL reserves used in formulating management’s overall operating decisions.

The Partnership does not operate its oil and natural gas properties and, therefore, receives actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well are used to estimate the accrual of revenue on these wells. The oil, natural gas and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, natural gas and NGLs. These variables could lead to an over or under accrual of oil, natural gas and NGL sales at the end of any particular quarter. However, the Partnership adjusts the estimated accruals of revenue to actual production in the period actual production is determined.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of our contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

Loss Per Common Unit

Basic net loss per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted net loss per unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no common units with a dilutive effect for the years ended December 31, 2016 and 2015. As a result, basic and diluted outstanding common units were the same. The Class B Units and Incentive Distribution Rights are not included in loss per common unit until such time that it is probable Payout (as discussed in Note 7) would occur.

Recent Accounting Standards

In January 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) 2017-01, Business Combinations (Topic 805), which amends the existing accounting standards to clarify the definition of a business and assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, including interim periods within those periods, and should be applied prospectively on or after the effective date. Early application is permitted for transactions that occur before the issuance or effective date of this amendment, provided the transaction has not been reported in financial statements that have been issued or made available for issuance. The Partnership plans to adopt the standard effective January 1, 2017. Prior to the adoption of this standard, the Partnership's acquisitions of oil and gas properties were accounted for as existing businesses, and therefore all transaction costs associated with the acquisitions, including title, legal, accounting, brokerage commissions and other related costs were expensed as incurred. The adoption of this standard will not affect transactions that occurred prior to the effective date; however, the Partnership will evaluate any future acquisition(s) of oil and gas properties under the revised standard and account for the acquisition as either an asset purchase or business combination depending on the particular facts and circumstances of the acquisition.

In November and August 2016, the FASB issued ASU 2016-18 and ASU 2016-15. Each update addresses and clarifies specific statement of cash flow (Topic 230) issues with the objective to reduce existing diversity in practice. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted. This standard is not expected to have a material impact on the Partnership's consolidated statements of cash flows.

Throughout 2016, the FASB has issued several updates to clarify specific topics originally described in ASU 2014-09, Revenue from Contracts with Customers (Topic 606). These updates include ASU 2016-08, ASU 2016-10, ASU 2016-12 and ASU 2016-20. ASU 2014-09, released in May 2014, amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. ASU 2014-09 was to be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. However, the FASB deferred the effective date by one year in August 2015 in ASU 2015-14. The Partnership currently does not believe this standard will have a material effect on the timing of its revenue recognition, its financial position or its results from operations. However, the Partnership will continue to evaluate the impact, if any, of ASU 2014-09 as well as the related subsequent pronouncements released.

In March 2016, the FASB issued ASU 2016-09, Compensation – Stock Compensation (Topic 718), which simplifies several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public entities, the guidance is effective for reporting periods beginning after December 15, 2016, and it is not expected to have a material impact on the Partnership's consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the existing accounting standards for lease accounting, including requiring lessees to recognize most leases on their balance sheets and making targeted changes to lessor accounting. The standard is effective for annual periods beginning after December 15, 2018, and interim periods within those years, with early adoption permitted. The standard requires a modified retrospective transition approach for all leases existing at, or entered into after, the date of initial application, with an option to use certain transition relief. The Partnership is currently evaluating the impact of adopting the new standard on its consolidated financial statements.

Note 3. Oil and Gas Investments

As of December 31, 2016, the Partnership owns an approximate 11% non-operated working interest in approximately 216 existing producing wells and approximately 257 future development locations in the Sanish field located in Mountrail County, North Dakota (the "Sanish Field Assets"). The Partnership acquired its interest in the Sanish Field Assets on December 18, 2015 for approximately $159.1 million, subject to post-closing adjustments. During the first half of 2016, the Partnership and the sellers ("Sellers") adjusted the purchase price for the settlement of operating activity that occurred prior to the closing date. The net impact of the purchase price adjustment was an increase to the purchase price of the asset of approximately $0.5 million. The Partnership has expensed, as incurred, transaction costs associated with the acquisition of the Sanish Field Assets. These costs included but were not limited to due diligence, reserve reports, legal and engineering services and site visits. The Partnership incurred transaction costs of $78,000 and $0.3 million in the years ended December 31, 2016 and 2015. The transaction costs incurred in 2016 primarily relate to the due diligence for the 2017 acquisition of additional interests in the same Sanish Field Assets discussed below.

The Partnership is a non-operator of the Sanish Field Assets. Whiting, one of the largest producers in this basin, is the operator.

The following unaudited pro forma financial information for the period ended December 31, 2015, has been prepared as if the acquisition of the Sanish Field Assets had occurred on January 1, 2015. The unaudited pro forma financial information was derived from the historical Statement of Operations of the Partnership and the historical information provided by the Sellers. The unaudited pro forma financial information does not purport to be indicative of the results of operations that would have occurred had the acquisition of the Sanish Field Assets and related financing occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

	Year Ended December 31, 2015 (Unaudited)
Revenues	$ 26,831,257
Net loss	$ (2,618,884)

On January 11, 2017, the Partnership completed the purchase of an additional 11% working interest in the Sanish Field Assets. The purchase price was $130.0 million and was funded by the Partnership with $90.0 million in cash (from the sale of the Partnership's common units in its ongoing, best-efforts offering) and a $40.0 million promissory note ("Seller Note"). The Partnership paid the $40.0 million Seller Note in full on February 23, 2017. The Seller Note bore interest at 5% per annum up to the payoff date.

Note 4. Note Payable

As part of the financing for the purchase of the Sanish Field Assets, on December 18, 2015, the Partnership executed a note in favor of the Sellers ("Seller Note") of the assets in the original principal amount of $97.5 million. On September 29, 2016, the Partnership paid the Seller Note in full.

On June 23, 2016, the Seller Note was increased by $5.0 million to satisfy the contingent payment due to the Sellers as defined in the First Amendment of the Interest Purchase Agreement. The Partnership was given the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to satisfy the contingent payment in full by paying to Sellers $5.0 million at the time of election or by increasing the amount of the Seller Note by $5.0 million. On June 23, 2016, the Partnership exercised that right by increasing the amount of the Partnership's note with the Sellers by $5.0 million. If the Partnership had not exercised the one-time right, the contingent payment would have ranged from $0 to $95 million depending on the average of the monthly NYMEX:CL strip prices as of December 31, 2017 for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022.

In accordance with the Seller Note, because the Partnership had not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership paid a deferred origination fee equal to $250,000 during the three months ended June 30, 2016. The deferred origination fee was amortized and expensed in full during the third quarter of 2016 and is included in "Interest expense, net" in the consolidated statements of operations.

As of December 31 2015, the outstanding balance on the note was $85.0 million and the carrying value of the note, which approximates its fair market value, was $81.7 million. The Partnership estimated the fair value of its note payable by discounting the future cash flows of the instrument at estimated market rates consistent with the maturity of a debt obligation with similar credit terms and credit characteristics, which are Level 3 inputs under the fair value hierarchy. Market rates take into consideration general market conditions and maturity.

Note 5. Fair Value of Financial Instruments

The Partnership follows authoritative guidance related to fair value measurement and disclosure, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement using market participant assumptions at the measurement date. Categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The three levels are defined as follows:

Level 1: Quoted prices in active markets for identical assets
Level 2: Significant other observable inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, either directly or indirectly, for substantially the full term of the financial instrument
Level 3: Significant unobservable inputs

The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and the consideration of factors specific to the asset or liability. The Partnership's policy is to recognize transfers in or out of a fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Partnership has consistently applied the valuation techniques discussed above for all periods presented. During the years ended December 31, 2016 and 2015, there were no transfers in or out of Level 1, Level 2, or Level 3 Assets and liabilities measured on a recurring basis.

The Partnership's financial instruments exposed to concentrations of credit risk primarily consist of cash and cash equivalents and accounts receivable. The carrying values for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities reflect these items' cost, which approximates fair value based on the timing of the anticipated cash flows and current market conditions. See "Note 4. Note Payable" for the fair value discussion on the debt.

Items required to be measured at fair value on a recurring basis by the Partnership include the contingent consideration included in the Partnership's consideration for the 2015 Sanish Field Asset purchase. Within the valuation hierarchy, the Partnership measured the fair value of the contingent consideration using Level 3 inputs. As of December 31, 2015, the fair value of the contingent consideration was $4,743,752. The inputs for this instrument were significant and unobservable and therefore classified as Level 3 inputs. Management calculated the fair value of the contingent consideration (absent the $5.0 million option) as of December 18, 2015, the Sanish Field Assets acquisition close date, to be $12.5 million. As this was substantially greater than the $5.0 million option, the Partnership believed a market participant would likely view the $5.0 million option as highly probable of being exercised and, therefore, valued the contingent consideration at $5.0 million, discounted to the expected exercise date. The calculation of this liability was based upon a $5.0 million payment to be made to Kaiser-Whiting between June 15, 2016 and June 30, 2016 and a discount rate that was reflective of the Partnership's market adjusted borrowing rate, as of December 18, 2015, of 11.15%. As discussed in "Note 4. Note Payable", the Partnership satisfied the contingent payment by increasing its Seller Note on June 23, 2016 by $5.0 million; therefore, the contingent consideration has no value as of December 31, 2016.

Note 6. Management Agreement

At the initial closing of the sale of its common units on August 19, 2015, the Partnership entered into a Management Services Agreement (the "Management Agreement") with E11 Management, LLC, (the "Former Manager"), and E11 Incentive Holdings, LLC, an affiliate of the Former Manager ("Incentive Holdings"), whereby the Former Manager agreed to provide management and operating services regarding substantially all aspects of the Partnership's business. The Former Manager was formed by Aubrey K. McClendon and he served as its Chief Executive Officer.

Under the Management Agreement, the Former Manager agreed to provide management and other services to the Partnership including, but not limited to, the following:

Identifying and evaluating oil and natural gas properties for acquisition, development, integration, sale or monetization;
Conducting (or overseeing one of its affiliated companies or third-parties to conduct) drilling, completion, production, marketing and hedging operations as the operator of the Partnership's oil and natural gas properties;
Overseeing the drilling, completion, production, marketing and hedging operations of our oil and natural gas properties operated by other persons or entities;
Identifying and evaluating financing alternatives for acquisitions of producing oil and natural gas properties; and
Managing the financial, accounting and other back office support functions associated with the drilling, completion, production, marketing and hedging of the Partnership's oil and natural gas properties.

Pursuant to the Management Agreement, the Partnership agreed to pay the Former Manager a monthly fee.

Upon entering into the Management Agreement, the Partnership issued 100,000 Class B units to Incentive Holdings. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Note 7 below.

The Management Agreement was terminable by the Partnership if, among other reasons, Mr. McClendon, the Former Manager's key employee, ceased to be employed by the Former Manager and the Partnership did not approve of a proposed replacement of such key employee. On March 2, 2016, Mr. McClendon died in a car accident. Following Mr. McClendon's death and subsequent correspondence between the Former Manager and the Partnership, on April 5, 2016, the Partnership elected not to approve a replacement key employee for Mr. McClendon and exercised its right to terminate the Management Agreement. Accordingly, the fees under the Management Agreement were no longer accrued as of the effective date of termination. Also, upon termination of the Management Agreement and in accordance with the terms therewith, 37.5% of the Class B units owned by Incentive Holdings were canceled. As of December 31, 2016, the Class B units owned by Incentive Holdings totaled 62,500.

Substantially all of the Partnership's properties are currently being operated by Whiting, an independent third party. Since the Partnership only owns a non-operating interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting, as operator of those properties. Consequently, the termination of the Management Agreement has not had and the Partnership does not anticipate that the termination will have an adverse effect on its operations.

For the years ended December 31, 2016 and 2015, the Partnership incurred fees and reimbursable costs of approximately $0.9 million and $0.5 million, respectively, under the Management Agreement.

Note 7. Capital Contribution and Partners' Equity

At inception, the General Partner and organizational limited partner made initial capital contributions totaling $1,000 to the Partnership. Upon closing of the minimum offering the organizational limited partner withdrew its initial capital contribution of $990, the General Partner received Incentive Distribution Rights (defined below), and has been and will be reimbursed for its documented third party out-of-pocket expenses incurred in organizing the Partnership and offering the common units.

As of August 19, 2015, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. In March 2016, the Partnership completed the sale of 5,263,158 common units at $19.00 per common unit. All subsequent shares of common units are being sold at $20.00 per common unit. As of December 31, 2016 and 2015, the Partnership had completed the sale of 14.6 million and 4.5 million common units for total gross proceeds of $286.4 million and $85.2 million, respectively, and proceeds net of offering costs including selling commissions and marketing expenses of $267.1 million and $78.3 million, respectively.

The Partnership intends to continue to raise capital through its best-efforts offering by the Dealer Manager at $20.00 per common unit. The Partnership has extended its offering through April 24, 2017; however, the offering will be terminated if all of the common units are sold before then. Under the agreement with the Dealer Manager, the Dealer Manager receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership. Based on the common units sold through December 31, 2016, the total contingent fee is approximately $11.5 million.

Prior to "Payout," which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights (owned by the General Partner), the Class B units or the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership's assets, will be made as follows:

First, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) to the Dealer Manager, as the contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any, to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000; (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest.

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed above in Note 6.

All items of income, gain, loss and deduction will be allocated to each Partner's capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2016, the Partnership paid distributions of $1.400000 per common unit, or $10.4 million. For the year ended December 31, 2015, the Partnership paid distributions of $0.510138 per common unit, or $1.3 million.

Note 8. Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to any existing related party transactions, as well as any new significant related party transactions.

On December 18, 2015, the General Partner appointed Clifford J. Merritt as its President. Prior to being appointed President, Mr. Merritt provided consulting services to the General Partner. For the years ended December 31, 2016 and 2015, the Partnership paid Mr. Merritt $338,396 and $222,099, respectively.

On July 1, 2016, the Partnership entered into a one-year lease agreement with an affiliate of the General Partner for office space in Oklahoma City, Oklahoma. Under the terms of the agreement, the Partnership will make twelve monthly payments of $8,537. For the year ended December 31, 2016, the Partnership paid $51,222 to the affiliate of the General Partner.

For the years ended December 31, 2016 and 2015, approximately $285,000 and $62,000 of general and administrative costs were incurred by a member of the General Partner and have been or will be reimbursed by the Partnership. At December 31, 2016, approximately $98,000 was due to a member of the General Partner.

During the year ended December 31, 2015 (subsequent to the completion of the minimum offering), the Partnership reimbursed two members of the General Partner approximately $1.8 million in total for offering related costs that had been paid by the members of the General Partner.

Glade M. Knight, Chief Executive Officer of our general partner, and David S. McKenney, Chief Financial Officer of our general partner, are the CEO and CFO of Sundance Energy, L.P., a newly-formed partnership with the primary investment objective to acquire non-operated working interests in oil and gas properties.

Note 9. Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of oil, natural gas and NGL properties and related accumulated depreciation, depletion and amortization as of December 31, 2016 and 2015 is as follows:

	2016	2015
Producing properties	$ 94,199,024	$ 90,167,047
Non-producing	67,264,748	69,119,768
	161,463,772	159,286,815
Accumulated depreciation, depletion and amortization	(9,908,800)	(391,624)
Net capitalized costs	$ 151,554,972	$ 158,895,191

Costs Incurred

For the years ended December 31, 2016 and 2015, the Partnership incurred the following costs in oil and natural gas producing activities:

	2016	2015
Property acquisition costs	$ 524,175	$ 159,216,768
Development costs	1,652,782	70,047
	$ 2,176,957	$ 159,286,815

Estimated Quantities of Proved Oil, NGL and Natural Gas Reserves

The following unaudited information regarding the Partnership's oil, natural gas and NGL reserves is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Proved oil and natural gas reserves are those quantities of oil, natural gas and NGLs which, by analysis of geosciences 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. 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. 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. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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. 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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of Pinnacle Energy of Oklahoma City, OK, prepared estimates of the Partnership's oil, natural gas and NGL reserves as of December 31, 2016 and 2015.

The Partnership's net proved oil, NGL and natural gas reserves, all of which are located in the contiguous United States, as of December 31, 2016 and 2015, have been estimated by the Partnership's independent consulting petroleum engineering firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate. Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available. "Revisions of previous estimates" in the table below represent changes in previous reserve estimates, either upward or downward, resulting from a change in economic factors, such as commodity prices, operating costs or development costs, or resulting from information obtained from the Partnership's production history.

Net quantities of proved, developed and undeveloped oil, natural gas and NGL reserves are summarized as follows:

	Proved Reserves			
	Oil (Bbls)	**Natural Gas (Mcf)**	**NGLs (Bbls)**	**Total (BOE)**
January 1, 2015	-	-	-	-
Acquisition	9,089,252	7,705,802	1,866,775	12,240,327
Extensions, discoveries and other additions	-	-	-	-
Production (December 18 - December 31)	(21,937)	(18,392)	(2,841)	(27,843)
December 31, 2015	9,067,315	7,687,410	1,863,934	12,212,484
Acquisition	-	-	-	-
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates	222,321	2,799,032	(576,645)	112,182
Production	(498,926)	(519,122)	(69,059)	(654,506)
December 31, 2016	8,790,710	9,967,320	1,218,230	11,670,160

In accordance with SEC Regulation S-X, Rule 4-10, as amended, the Partnership uses the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2016 were $42.75 per barrel of oil and $2.48 per Mcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2016 were $36.25 per barrel of oil, ($0.38) per Mcf of natural gas and $4.70 per barrel of NGL.

The oil, natural gas and NGL prices used in computing the Partnership's reserves as of December 31, 2015 were $50.28 per barrel of oil, $2.59 per Mcf of natural gas, and $15.74 per barrel of NGL, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2015 were $41.74 per barrel of oil, $1.46 per Mcf of natural gas and $9.77 per barrel of NGL.

	Oil (Bbls)	**Natural Gas (Mcf)**	**NGLs (Bbls)**	**Total (BOE)**
Proved developed reserves:				
December 31, 2015	5,602,387	3,964,052	961,147	7,224,210
December 31, 2016	4,748,350	5,163,240	631,080	6,239,970
Proved undeveloped reserves:				
December 31, 2015	3,464,928	3,723,358	902,787	4,988,274
December 31, 2016	4,042,360	4,804,080	587,150	5,430,190

The following details the changes in proved undeveloped reserves for 2015 and 2016:

	BOE
Proved undeveloped reserves, beginning	-
Acquisition	4,988,274
Proved undeveloped reserves, December 31, 2015	4,988,274
Revisions of previous estimates	441,916
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430,190

Although the Partnership has performed limited drilling since acquisition, we anticipate that all the Partnership's current PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves which are no longer projected to be drilled within five years from the date they were first booked as proved undeveloped reserves will be removed as revisions at the time that determination is made, and in the event that it subsequently appears that any such undrilled PUD locations would not be drilled by the end of such five-year period, then the Partnership would remove the reserves associated with those locations from the its proved reserves as revisions.

Standardized Measure of Discounted Future Net Cash Flows

Accounting standards prescribe guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Partnership has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year.

The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect the Partnership's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates affect the valuation process.

	2016	2015
Future cash inflows	$ 320,606,188	$ 407,928,626
Future production costs	(122,527,901)	(136,547,001)
Future development costs	(43,050,408)	(37,640,024)
Future net cash flows	155,027,879	233,741,601
10% annual discount	(94,081,952)	(134,551,759)
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

Changes in the standardized measure of discounted future net cash flows are as follows:

	2016	2015
Standardized measure at beginning of period	$ 99,189,842	$ -
Changes resulting from:		
Acquisition of reserves	524,175	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(14,693,814)	(480,274)
Net changes in prices and production costs	(28,508,492)	-
Development costs incurred during the period	1,652,782	-
Revisions to previous estimates	8,191,818	-
Change in estimated future development costs	(5,410,384)	-
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

Note 10. Quarterly Financial Data (Unaudited)

The following is a summary of quarterly results of operations for the years ended December 31, 2016 and 2015. Net income (loss) per common unit is non-additive in comparison to net income (loss) per common unit for each year due to the timing and size of the Partnership's common unit issuances.

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 4,319,097	$ 5,532,113	$ 5,434,047	$ 5,080,081
Net income (loss)	$ (3,592,456)	$ (859,383)	$ (1,511,146)	$ 732,421
Basic and diluted net income (loss) per common share	$ (0.73)	$ (0.14)	$ (0.20)	$ 0.06

	2015 (1)			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ -	$ -	$ -	$ 703,806
Net loss	$ (55,135)	$ (104,216)	$ (465,643)	$ (937,822)
Basic and diluted net loss per common share	$ -	$ -	$ (0.62)	$ (0.32)

(1) The Partnership did not acquire its first operating asset until December 18, 2015.

Note 11. Subsequent Events

On January 11, 2017, the Partnership closed on the purchase of all of the issued and outstanding limited liability company interests of Kaiser-Whiting, LLC, which represents an additional approximate 11% non-operated working interest in the Sanish Field Assets. The purchase price of $130.0 million, subject to customary adjustments, consisted of cash payments totaling $90.0 million and the delivery of a promissory note in favor of the seller of $40.0 million. The Partnership paid the $40.0 million promissory note in full on February 23, 2017. With the closing of the purchase, the Partnership now owns an approximate 22-23% non-operated working interest in the Sanish Field Assets. See Note 3. Oil and Gas Investments for more information.

In January 2017, the Partnership declared and paid $1.6 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In January 2017, the Partnership closed on the issuance of approximately 1.1 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $21.7 million and proceeds net of selling and marketing costs of approximately $20.4 million.

In February 2017, the Partnership declared and paid $1.7 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In February 2017, the Partnership closed on the issuance of approximately 1.0 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $20.4 million and proceeds net of selling and marketing costs of approximately $19.2 million.

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of December 31, 2016 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act. We have performed an evaluation under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of our internal control over financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2016. Our management used the criteria set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) to perform its assessment. Based on this assessment, our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded, that as of December 31, 2016, our internal control over financial reporting was effective based on those criteria.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Directors and Executive Officers of the General Partner

As is the case with many partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by the board of directors and executive officers of our General Partner. References to our directors and executive officers are references to the directors and executive officers of our General Partner.

The following table sets forth the names, ages and offices of the present directors and executive officers of the General Partner as of December 31, 2016.

Name	Age	Position
Glade M. Knight	72	*Chairman of the Board and Chief Executive Officer*
David S. McKenney	54	*Director and Chief Financial Officer and Secretary*
Anthony Francis “Chip” Keating III	37	*Director and Co-Chief Operating Officer*
Michael J. Mallick	54	*Director and Co-Chief Operating Officer*
Clifford J. Merritt	56	*President*

The following is a biographical summary of the business experience of these directors and executive officers:

Glade M. Knight. Mr. Knight has been Chairman of the Board and Chief Executive Officer of the General Partner since its formation in July 2013. Mr. Knight is also the Chief Executive Officer of Sundance Energy, L.P., a newly-formed oil and gas limited partnership. Mr. Knight also serves as Executive Chairman of Apple Hospitality REIT, Inc. since May 15, 2014, and previously served as Chairman and Chief Executive Officer. Mr. Knight was also the founder of Apple REIT Ten, Inc. and served as its Chairman and Chief Executive Officer from its inception until it merged with Apple Hospitality REIT, Inc. in September 2016. Mr. Knight was also the founder of Apple REIT Seven, Inc. and Apple REIT Eight, Inc. (which were real estate investment trusts) and served as the Chairman and Chief Executive Officer of those companies from their inception until the mergers with the Apple Hospitality REIT, Inc., which were completed in March 2014. In addition, Mr. Knight was the Chairman and Chief Executive Officer of Apple REIT Six, Inc., a real estate investment trust, from 2004 until the company merged with an affiliate of Blackstone Real Estate Partners VII in May 2013. Mr. Knight served in the same capacity for Apple Hospitality Five, Inc., another REIT, from 2002 until the company was sold to Inland American Real Estate Trust, Inc. in October 2007, and Apple Hospitality Two, Inc., a REIT, from 2001 until it was sold to an affiliate of ING Clarion in May 2007. In addition, Mr. Knight served as Chairman and Chief Executive Officer of Cornerstone Realty Income Trust, Inc. from 1993 until it merged with a subsidiary of Colonial Properties Trust in 2005. Following the merger in 2005 until April 2011, Mr. Knight served as a trustee of Colonial Properties Trust. Cornerstone Realty Income Trust, Inc. owned and operated apartment communities in Virginia, North Carolina, South Carolina, Georgia and Texas. Mr. Knight is the founding Chairman of Southern Virginia University in Buena Vista, Virginia. He also is a member of the Advisory Board to the Graduate School of Real Estate and Urban Land Development at Virginia Commonwealth University. Additionally, he serves on the National Advisory Council for Brigham Young University and is a founding member of the University’s Entrepreneurial Department of the Graduate School of Business Management. On February 12, 2014, Mr. Knight, Apple REIT Seven, Inc. (“Apple Seven”), Apple REIT Eight, Inc. (“Apple Eight”), Apple REIT Nine, Inc. (“Apple Nine”) and their related advisory companies entered into settlement agreements with the SEC. Along with Apple REIT Seven, Apple REIT Eight, Apple REIT Nine and their advisory companies, and without admitting or denying the SEC’s allegations, Mr. Knight consented to the entry of an administrative order, under which Mr. Knight and the noted companies each agreed to cease and desist from committing or causing any violations of Sections 13(a), 13(b)(2)(A), 13(b)(2)(B), 14(a), and 16(a) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and Rules 12b-20, 13a-1, 13a-13, 13a-14, 14a-9, and 16a-3 thereunder.

David S. McKenney. Mr. McKenney has been a Director and Chief Financial Officer and Secretary of the General Partner since its formation in July 2013. Mr. McKenney is also the Chief Financial Officer of Sundance Energy, L.P., a newly-formed oil and gas limited partnership. Mr. McKenney also serves as Senior Advisor for Apple Hospitality REIT, Inc., a real estate investment trust. Mr. McKenney was the President of Capital Markets of Apple REIT Ten, Inc. from its inception until it merged with Apple Hospitality REIT, Inc. in September 2016. Mr. McKenney previously served as President of Capital Markets for Apple Hospitality REIT, Inc. In addition, Mr. McKenney was the President of Capital

Markets of Apple REIT Six, Inc., a real estate investment trust, from 2004 until the company merged with an affiliate of Blackstone Real Estate Partners VII in May 2013. Mr. McKenney served in the same capacity for Apple Hospitality Five, Inc., a lodging REIT, from 2002 until the company was sold to Inland American Real Estate Trust, Inc. in October of 2007, and Apple Hospitality Two, Inc., a lodging REIT, from 2001 until the company was sold to an affiliate of ING Clarion in May of 2007. From 1994 to 2001, Mr. McKenney served as Senior Vice President and Treasurer of Cornerstone Realty Income Trust, Inc., a REIT that owned and operated apartment communities in Virginia, North Carolina, South Carolina, Georgia and Texas. From 1992 to 1994, Mr. McKenney served as Chief Financial Officer for The Henry A. Long Company, a regional development firm located in Washington, D.C. From 1988 to 1992, Mr. McKenney served as a Controller at Bozzuto & Associates, a regional developer of apartments and condominiums in the Washington, D.C. area. Mr. McKenney holds Bachelor of Science degrees in Accounting and Management Information Systems from James Madison University.

Anthony Francis "Chip" Keating III. Mr. Keating has been a Director and Co-Chief Operating Officer of the General Partner since its formation in July 2013. Mr. Keating has been a principal with Rock Creek Capital, a real estate and oil and gas investment company, since March 2010. He served on the board of Apple REIT Ten, Inc. until the merger with Apple Hospitality REIT, Inc. in September 2016. He is currently the Chairman elect of the board of The Children's Hospital Foundation in Oklahoma City. Mr. Keating is also a Director and Gubernatorial appointee of The Oklahoma Law Enforcement Retirement System by Governor Mary Fallin, and a director of Leadership Oklahoma City, The Downtown Club of Oklahoma City and International Council of Shopping Centers. Prior to founding Rock Creek Capital, Mr. Keating served as the Real Estate Development Manager for Chesapeake Energy Corporation in Oklahoma City, Oklahoma from March 2007 to March 2010. While at Chesapeake, Mr. Keating closed and transacted over $850 million in real estate transactions ranging from corporate headquarters, sale leasebacks, field offices, investment properties and raw land in urban natural gas plays for drill sites. Prior to joining Chesapeake, Mr. Keating worked as a commercial real estate broker with Trammell Crow Company from August 2004 to March 2007. While at Trammell Crow Company, he specialized in tenant representation and investment sales. Before joining Trammell Crow Company, he spent over three years as an Oklahoma State Trooper from May 2001 to August 2004. Mr. Keating received a Bachelor of Business Administration from Southern Methodist University.

Michael J. Mallick. Mr. Mallick has been a Director and Co-Chief Operating Officer of the General Partner since its formation in July 2013. Mr. Mallick is the founder of Fort Worth, Texas-based Mallick Group, Inc., a real estate and energy-related investment firm. Mr. Mallick is a principal investor in various entities and serves as the principal officer of sponsoring and managing partners for numerous and diverse real estate investments and energy-related interests funded with established co-investment relationships with high net worth private investors, institutional investors and lenders. Mr. Mallick's varied experience includes development of the 349 room Horseshoe Bay Marriot Resort Hotel, located in Horseshoe Bay, Texas (financed with a national pension fund); Sierra Vista, a redevelopment initiative in a public/private partnership with the City of Fort Worth, Texas, including the assemblage and acquisition of approximately 300 acres located within a concentration of blight inside the central city and resulting in environmental remediation and demolition of 1,000 crime-ridden apartment units and new quality affordable housing and shopping; and acquisition of a large multi-property portfolio of properties financed via a structured private placement offering with multiple institutional investors. Mr. Mallick serves on the Board of Directors of S2K Financial, LLC, a New York based financial services firm.

Clifford J. Merritt. On December 18, 2015, Mr. Merritt was appointed as President of the General Partner. Mr. Merritt had been a consultant to us since July 1, 2014, and to other private exploration and development companies since November 2013. Prior to that time and since 2004 he was employed by Chesapeake Energy Corporation. From 2010 to 2013 he served as Chesapeake's Vice President Land – Southern Division and from 2005 to 2010 as Chesapeake's Land Manager – Barnett Shale District. Before joining Chesapeake he worked for Okland Oil, Ricks Exploration and Concho Resources during the years of 1990 through 2003, each of which is an independent oil and gas company. He has a B.B.A. from the University of Central Oklahoma and is a member of OCAPL (Oklahoma City Association of Professional Landmen) and AAPL (American Association of Professional Landmen). During his career, Mr. Merritt has been involved and managed the Land functions of numerous acquisitions and divestitures of oil and gas properties and supervised the drilling and completion of over 2,000 oil and gas wells throughout multiple states in the continental US.

Code of Ethics

Our General Partner has adopted a Code of Business Conduct and Ethics that applies to the executive officers of the General Partner and other persons performing services for the General Partner and our Partnership, generally. This Code of Business Conduct and Ethics is posted on our website, at www.energyeleven.com.

Audit and Compensation Committee

We do not have a formal compensation committee and our Board of Directors serves as our audit committee. Because we do not have and are not seeking to list any securities on a national securities exchange or on an inter-dealer quotation system, we are not subject to a number of the corporate governance requirements of the SEC or of any national securities exchange or inter-dealer quotation system. For example, we are not required to have a board of directors comprised of a majority of independent directors or to have an audit committee comprised of independent directors. Accordingly, our Board of Directors has not made any determination as to whether any of the members of our Board of Directors or committees thereof would qualify as independent under the listing standards of any national securities exchange or any inter-dealer quotation system or under any other independence definition. Additionally, for the same reason, we have not yet determined whether any of our directors is an audit committee financial expert.

Our General Partner

Our General Partner is Energy 11 GP, LLC. Our General Partner was formed in 2013 and has no operating history. Our General Partner was formed and is owned by companies controlled by Glade M. Knight, David S. McKenney, Anthony "Chip" F. Keating III, and Michael J. Mallick.

Our General Partner will not receive a management or similar fee for acting as General Partner and will not receive an offering and organization fee for organizing the Partnership. We will reimburse our General Partner for all third party costs incurred and paid by the General Partner in connection with the formation of the Partnership, including third-party legal, accounting, printing, filing fees, travel and similar third party costs and expenses. In addition, the Partnership will reimburse the General Partner and its affiliates for all general and administrative expenses incurred by the General Partner and its affiliates in managing the Partnership's business. These costs and expenses will include the direct and indirect costs and expenses of employee compensation, rental, office supplies, travel and entertainment, printing, legal, accounting, advertising, marketing and overhead. The beneficial owners of the General Partner will not be employees of the General Partner, and will not receive salary or other compensation from the General Partner or Partnership other than reimbursement of third party costs and expenses and with respect to their equity interests in the Partnership.

Item 11. Executive Compensation

Summary Compensation

The following table summarizes, with respect to each of the Chief Executive Officer and the two other most highly compensated officers of our General Partner (the "Named Executive Officers"), information relating to the compensation earned for services rendered in all capacities during the fiscal years ended December 31, 2016, 2015 and 2014. Since the only person being paid any compensation by the Partnership or the General Partner is Mr. Merritt, the Named Executive Officers only include Mr. Knight, our Chief Executive Officer, and Mr. Merritt.

Name and Principal Position:	Year	Salary	Bonus	All Other Compensation	Total
Glade M. Knight	2016	$ —	$ —	$ —	$ —
Chairman of the Board and Chief Executive Officer	2015	$ —	$ —	$ —	$ —
	2014	$ —	$ —	$ —	$ —
Clifford J. Merritt (1)	2016	$ 308,396	$ 30,000	$ —	$ 338,396
President	2015	$ 222,009	$ —	$ —	$ 222,009

(1) Mr. Merritt was appointed the President of the General Partner in December 2015.

We do not directly employ any of the persons responsible for managing our business. Instead, our General Partner manages our day to day affairs and provides us with management and operating services. The owners of our General Partner will be reimbursed for documented out-of-pocket travel, entertainment and similar expenses incurred by them in connection with attending board of directors meetings or managing the Partnership's business. The owners of the General Partner will not receive any salary, bonus or consulting fees for serving on the board of directors or managing the Partnership's business other than distributions in accordance with the incentive distribution rights, if any.

The General Partner has agreed to pay Mr. Merritt base compensation of $300,000, basic health insurance benefits, which will be paid or reimbursed to the General Partner by the Partnership and a 5% interest in the General Partner's incentive distribution rights.

Outstanding Equity Awards at Fiscal Year-End

There were no outstanding equity awards for our named executive officers as of December 31, 2016, other than the Incentive Distribution Rights.

Compensation of Directors

The employee and non-employee members of the General Partner's board of directors do not receive compensation for their services as directors. However, our directors may be reimbursed for their expenses in attending board meetings.

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

The following table sets forth as of March 3, 2017 the beneficial ownership of our common units that are owned by:

all persons who, to the knowledge of our management team, beneficially own more than 5% of our common units;
each executive officer of our General Partner; and
all current directors and executive officers of our General Partner as a group.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage Of Common Units Beneficially Owned
Glade M. Knight 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*
David S. McKenney 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*
Anthony Francis "Chip" Keating III 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*
Michael J. Mallick 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*
Clifford J. Merritt 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	—	—
Directors and principal officers as a group (5 persons)	20,000	*

* Less than 1% of outstanding common units.

Class B Units

E11 Incentive Holdings, LLC owns 62,500 Class B units. The address of E11 Incentive Holdings, LLC is 301 NW 63rd Street, Suite 400, Oklahoma City, Oklahoma 73116.

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed in Note 6 of Part II, Item 8 of this Form 10-K.

Ownership of Our General Partner

Our General Partner is a limited liability company. The members of our General Partner and the membership interest owned are as follows:

GKOG, LLC, owns a 25% membership interest in our General Partner. GKOG, LLC is a limited liability company wholly owned by Mr. Knight.
DMOG, LLC owns a 25% membership interest in our General Partner. DMOG, LLC is a limited liability company wholly owned by Mr. McKenney.
CFK Energy, LLC owns a 25% membership interest in our General Partner. CFK Energy, LLC is a limited liability company owned by Mr. Keating and his immediate family.
Pope Energy Investors, LP, a limited partnership, owns a 25% membership interest in our General Partner. The General Partner and the limited partner interests of Pope Energy Investors, LP are owned by Mr. Mallick and his immediate family.

Each member of our General Partner has the right to appoint one person to the General Partner's board of directors. All decisions regarding the business of our General Partner and our Partnership will be made by the board of directors of our General Partner at meetings of the board of directors at which a quorum is present. The presence of a majority of the directors constitutes a quorum, and the vote of a majority of a quorum constitutes a decision by the board of directors.

The owners of the members of our General Partner have granted each other the right of first refusal to acquire any interests in the members of our General Partner that the owners propose to sell. If the owners of the members of our General Partner do not exercise the right of first refusal, the purchaser of the owner of our General Partner will have the right to appoint a member to our board of directors, and if a person or group of affiliated persons were to acquire a controlling interest in three of the owners of our General Partner, the person would be able to control our General Partner and the Partnership. Our Partnership Agreement does not give the holders of common units the right to cause an owner of our General Partner to exercise its buy-sell right, or provide the holders the right to consent to or otherwise approve the transfer by an owner of our General Partner of its membership interest in our General Partner. Our General Partner does, however, agree not to permit a change of control of our General Partner to occur. A change of control is defined as a person who is not currently a beneficial owner of our General Partner or a "qualifying owner" becoming the beneficial owner of 50% or more of the membership interest in our General Partner. A qualifying owner generally is defined as the following with respect to the current beneficial owners of our General Partner: conservators, guardians, executors, administrators, and similar persons of any trust, private foundation or custodianship that such beneficial owner, his spouse, lineal descendants or estate is a beneficiary.

Securities Authorized for Issuance under Equity Compensation Plans

We do not have any equity compensation plans.

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

Reimbursement of Expenses to General Partner in Connection with Offering Costs

Our Partnership Agreement provides that the General Partner is entitled to be reimbursed out of capital contributions for offering and organization costs paid to third parties, including legal, accounting, engineering, printing and filing fees. During the year ended December 31, 2015, Apple Realty Group, an affiliate of GKOG, LLC, was reimbursed $1,544,372 and Pope Energy Investors, LP was reimbursed $209,783 in 2015 for offering and organizational costs paid by such members of the General Partner.

Reimbursement of Expenses to General Partner in Connection with Operations of the Partnership

The Partnership will also reimburse the General Partner and the General Partner's affiliates for their General and administrative costs allocable to the Partnership. These expenses will include compensation expense, rent, travel, and other general and administrative and overhead expenses. Currently, the only business of the General Partner is to act as General Partner of the Partnership, and all of the General Partner's general and administrative costs will be paid by the Partnership. If affiliates of the General Partner form other partnerships or engage in other oil and gas activities, the General Partner will allocate its general and administrative costs to the Partnership and other partnerships or businesses in a manner deemed reasonable by the General Partner.

During the years ended December 31, 2016 and 2015, approximately $285,000 and $62,000, respectively, of related party costs were incurred by a member of the General Partner and reimbursed by us in connection with our operations.

Incentive Distribution Rights

On the initial closing date, we issued incentive distribution rights, which are nonvoting limited partner interests that entitle the holder of such rights to 35% of all amounts distributed by us after Payout occurs, to our General Partner.

Consulting Fees to Clifford Merritt

On December 18, 2015 the General Partner, appointed Clifford J. Merritt as its President. Prior to being appointed President Mr. Merritt provided consulting services to the General Partner. For the years ended December 31, 2016 and 2015, Mr. Merritt was paid $338,396 and $222,099, respectively.

Director Independence

Because we do not have a class of securities listed on any national securities exchange, national securities association or inter-dealer quotation system, we are not required to have a board of directors comprised of a majority of independent directors under SEC rules or any listing standards. Accordingly, our Board of Directors has not made any determination as to whether the non-employee directors satisfy any independence requirements applicable to board members under the rules of the SEC or any national securities exchange, inter-dealer quotation system or any other independence definition.

Item 14. Principal Accountant Fees and Services

Grant Thornton LLP ("Grant Thornton") has audited our consolidated financial statements for the most recent fiscal year ended December 31, 2016. Grant Thornton was selected and appointed as our independent registered public accounting firm on March 18, 2015.

For the fiscal years ended December 31, 2016 and 2015, fees paid or payable to Grant Thornton for services performed in connection with the audit of the 2016 financial statements, the audit of the 2015 financial statements, reviews of the amended S-1s, SEC comment letters, issuance of consents and 2016 and 2015 interim reviews are as follows:

Audit Fees

	Year Ended December 31, 2016	Year Ended December 31, 2015
Audit fees	$ 149,150	$ 99,900
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$ 149,150	$ 99,900

Pre-Approval Policies and Procedures

We currently have no Board committees. Our Board of Directors has adopted policies regarding the pre-approval of auditor services. Specifically, the Board of Directors approves all services provided by the independent public accountants at its March meeting. All additional services must be pre-approved on a case-by-case basis. Our Board of Directors reviews the actual and budgeted fees for the independent public accountants periodically at regularly scheduled board meetings. All of the services provided by Grant Thornton during fiscal 2016 and 2015 were approved by the Board of Directors.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report:

1. Financial Statements:

(i) Report of Independent Registered Public Accounting Firm – Grant Thornton LLP

(ii) Consolidated Balance Sheets as of December 31, 2016 and December 31, 2015

(iii) Consolidated Statements of Operations for the years ended December 31, 2016, 2015 and 2014

(iv) Consolidated Statements of Partners' Equity (Deficit) for the years ended December 31, 2016, 2015 and 2014

(v) Consolidated Statements of Cash Flows for the years ended December 31, 2016, 2015 and 2014

(vi) Notes to Financial Statements

2. Financial Statement Schedules:

(i) All schedules are omitted as they are not applicable, not required or the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits:

The following exhibits are included, or incorporated by reference, in this Annual Report on Form 10-K, for the year ended December 31, 2016 (and are numbered in accordance with Item 601 of Regulation S-K). Exhibits incorporated by reference to this Form 10-K as listed below are available at www.sec.gov.

EXHIBIT NUMBER	Description Of Exhibit
1.1	Exclusive Dealer Manager Agreement with David Lerner Associates, Inc. (incorporated by reference from Exhibit 1.1 to Amendment No. 7 to the Partnership's Registration Statement on Form S-1 filed on December 31, 2014).
2.1	Interest Purchase Agreement dated September 15, 2015 among Energy 11 Operating Company, LLC, Kaiser-Whiting, LLC, and the owners of all the limited liability company interests in Kaiser-Whiting, LLC (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed with the SEC on September 18, 2015).
2.2	First Amendment to Interest Purchase Agreement dated December 18, 2015, by and among Energy 11 Operating Company, LLC, a Delaware limited liability company, Kaiser-Whiting, LLC, an Oklahoma limited liability company and Don P. Millican as attorney-in-fact on behalf of all Sellers (incorporated by reference from Exhibit 2.2 to the Partnership's Current Report on Form 8-K filed with the SEC on December 21, 2015).
2.3	Exclusive Option Agreement dated November 3, 2016 among Energy 11 Operating Company, LLC, Kaiser-Whiting, LLC, and Don P. Millican (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed with the SEC on November 4, 2016).
2.4	Interest Purchase Agreement dated January 4, 2017 among Energy 11 Operating Company, LLC, Kaiser-Whiting, LLC, and the owners of Kaiser-Whiting, LLC (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed with the SEC on January 12, 2017).
2.5	First Amendment to Interest Purchase Agreement by and among Energy 11 Operating Company, LLC, a Delaware limited liability company, Kaiser-Whiting, LLC, an Oklahoma limited liability company and the owners of all the limited liability company interests in Kaiser-Whiting, LLC.*

EXHIBIT NUMBER	Description Of Exhibit
3.1	Certificate of limited partnership of Energy 11, L.P. (incorporated by reference from Exhibit 3.1 to Amendment No. 4 to the Partnership's Registration Statement on Form S-1 filed on November 21, 2014).
3.2	First Amended and Restated Limited Partnership Agreement of Energy 11, L.P. dated as of August 19, 2015 (incorporated by reference from Exhibit A to the Prospectus included as part of the Amendment No. 6 to the Partnership's Registration Statement on Form S-1 filed on December 12, 2014).
10.1	Form of Subscription Agreement (incorporated by reference from Exhibit B to the Prospectus included as part of Amendment No. 6 to the Partnership's Registration Statement on Form S-1 filed with the SEC on December 12, 2014).
10.2	Letter Agreement between Energy 11 GP, LLC and Clifford Merritt (incorporated by reference from Exhibit 10.2 to the Partnership's Current Report on Form 8-K filed with the SEC on December 21, 2015).
10.3	Secured Promissory Note dated January 11, 2017 executed by Energy 11 Operating Company, LLC in favor of Kaiser-Francis Management Company, L.L.C. (incorporated by reference from Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed with the SEC on January 12, 2017).
21.1	Subsidiaries of the Partnership.*
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002*
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002*
32.1	Certification of Chief Executive Officer Pursuant to Section 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 Pursuant to Section 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
99.1	Report of Pinnacle Energy Services, LLC, Independent Petroleum Consultants.*
101	Interactive Data Files.*

*Filed herewith.

SIGNATURES

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

ENERGY 11, L.P.

By: Energy 11 GP, LLC, its General Partner

By: /s/ David S. McKenney
David S. McKenney
Chief Financial Officer

Date: March 3, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title with General Partner	Date
/s/ Glade M. Knight Glade M. Knight	Director, Chief Executive Officer (principal executive officer)	March 3, 2017
/s/ David S. McKenney David S. McKenney	Director, Chief Financial Officer (principal financial and accounting officer)	March 3, 2017
/s/ Anthony F. Keating III Anthony F. Keating III	Director, Co-Chief Operating Officer	March 3, 2017
/s/ Michael J. Mallick Michael J. Mallick	Director, Co-Chief Operating Officer	March 3, 2017

EXHIBIT 2.5

FIRST AMENDMENT TO INTEREST PURCHASE AGREEMENT

This First Amendment to Interest Purchase Agreement (this "*Amendment*") is entered into as of February 15, 2017, by and among Energy 11 Operating Company, LLC, a Delaware limited liability company ("*Buyer*"), Kaiser-Whiting, LLC, an Oklahoma limited liability company ("*Target*"), and the Persons who are the owners of all the limited liability company interests in Target (the "*Sellers*", and together, with Target, the "*Owners*"). Buyer and Owners are referred to collectively herein as the "*Parties.*" Capitalized terms used herein and not otherwise defined shall have the meaning ascribed to such terms in the hereinafter defined Agreement.

WHEREAS, the Parties entered into that certain Interest Purchase Agreement dated as of January 4, 2017 (the "*Agreement*"); and

WHEREAS, the Parties desire to amend the Agreement as set forth herein.

NOW, THEREFORE, in consideration of the premises and the mutual promises herein made, and in consideration of the representations, warranties, and covenants herein contained, the Parties agree as follows.

1.01. Amendment to Section 2.06. Section 2.06 of the Agreement is hereby deleted in its entirety and replaced with the following:

(a) Within 120 days after the Closing Date (*provided*, however, and notwithstanding the foregoing, not before ninety (90) days after the Closing Date), Seller Representative will prepare and deliver to Buyer, in accordance with this Agreement, a proposed statement (the "*Final Settlement Statement*") setting forth each adjustment to the Purchase Price to be made pursuant to Section 2.04 (including, but not counting twice the interim adjustments to the Purchase Price pursuant to Section 2.06(b)), along with supporting documentation reasonably necessary to support Sellers' calculations and all back up invoices, statements and other materials, and the resulting final Purchase Price (as such final Purchase Price is agreed by Buyer and Seller Representative or determined pursuant to this Section 2.06, the "*Final Purchase Price*"). Within 30 days after receipt of the preliminary Final Settlement Statement, Buyer shall return a written report containing any proposed changes to the preliminary Final Settlement Statement (a "*Dispute Notice*") and/or request additional supporting documentation or information. Buyer and Seller Representative agree to use commercially reasonable efforts to finalize such post-Closing adjustments no later than 180 days after the Closing Date (the date such agreement is made or such adjustments are otherwise determined pursuant to this Section 2.06, the "*Final Settlement Date*"). In the event that (i) the Closing Purchase Price, as determined pursuant to Section 2.05, is more than the Final Purchase Price, within two Business Days after the Final Settlement Date, Sellers shall pay to Buyer the amount of such difference, or (ii) the Closing Purchase Price, as determined pursuant to Section 2.05, is less than the Final Purchase Price, within two Business Days after the Final Settlement Date, Buyer shall pay to Sellers the amount of such difference, in either event by wire transfer or other immediately available funds to the account notified by Seller Representative or Buyer, as the case may be. If Seller Representative and Buyer are unable to resolve the matters addressed in the Dispute Notice within 210 days after the Closing Date, each of Buyer and Seller Representative shall, within ten Business Days after such deadline, summarize its position with regard to such dispute in a written document of 20 pages or less (exclusive of exhibits) and submit such summaries to a nationally or internationally recognized accounting firm with expertise in the oil and gas industry and that is otherwise reasonably acceptable to and mutually accepted by Buyer and Seller Representative, but who has not worked as an employee or outside counsel or consultant for any Party or its Affiliates during the five year period preceding the arbitration or have any financial interest in the dispute, (the "*Accounting Arbitrator*"), together with the Dispute Notice, the Final Settlement Statement and any other documentation such Party may desire to submit. Within 30 days after receiving Buyer's and Seller Representative's respective submissions, the Accounting Arbitrator shall render a decision choosing either Seller Representative's position or Buyer's position with respect to each matter addressed in the Parties' respective submissions, based on the materials described above. Any decision rendered by the Accounting Arbitrator pursuant hereto shall be final, conclusive and binding on Sellers and Buyer. The costs of such Accounting Arbitrator shall be borne one-half by Buyer and one-half by Sellers. The Accounting Arbitrator shall act as an expert for the limited purpose of determining the specific Final Purchase Price dispute presented to it, shall be limited to the procedures set forth in this Section 2.06, shall not have the powers of an arbitrator, shall not consider any other disputes or matters, and may not award damages, interest, costs, attorney's fees, expenses or penalties to any Party.

(b) Notwithstanding the above, Sellers will remit, or cause to be remitted, to Buyer all items of revenue, net of expenses, that Nominee or Target receive from Whiting Oil and Gas Corporation and Slawson Exploration Company, Inc. as respects the items set forth in the Nominee ABOS and/or the Company ABOS and attributable to the period from and after the Effective Time, together with summary of such items of revenue and expenses, within ten (10) business days after each receipt thereof.

1.02. Effect of Amendment. This Amendment shall be deemed incorporated into and made a part of the Agreement and shall be effective as of the date hereof. The provisions of this Amendment shall constitute an amendment to the Agreement, and to the extent that any term of provision of this Amendment may be deemed expressly inconsistent with any term or provision in the Agreement, this Amendment shall govern and control. Except as expressly stated herein, all of the terms, conditions and provisions of the Agreement are hereby ratified and confirmed in all respects, and the Agreement is and shall be unchanged and remains in full force and effect.

1.03. Severability. In the event any provision of this Amendment, or the application of such provision to any Person or set of circumstances, shall be determined to be invalid, unlawful, or unenforceable to any extent for any reason, the remainder of this Amendment, and the application of such provision to Persons or circumstances other than those as to which it is determined to be invalid, unlawful, or unenforceable, shall not be affected and shall continue to be enforceable to the fullest extent permitted by Law.

1.04. Headings. The Article and Section headings contained in this Amendment are inserted for convenience only and shall not affect in any way the meaning or interpretation of this Amendment.

1.05. Governing Law. This Amendment shall be governed by and construed in accordance with the internal Laws of the State of Oklahoma (without regard to or application of any conflict of laws principles).

1.06. Counterparts. This Amendment may be executed in one or more counterparts (including by means of facsimile or digitized transmission), each of which shall be deemed an original but all of which together will constitute one and the same instrument. The execution and delivery of this Amendment by any Party may be evidenced by facsimile or other electronic transmission (including scanned documents delivered by email), which shall be binding upon all Parties.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties hereto have executed this Amendment as of the day and year first above written.

BUYER: **ENERGY 11 OPERATING COMPANY, LLC**

By /s/ Anthony F. Keating, III
Name: Anthony F. Keating, III
Title: Co-Chief Operating Officer

Buyer Signature Page to First Amendment to Interest Purchase Agreement

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement as of the date first above written.

SELLER:

SELLER REPRESENTATIVE (in its capacity as attorney in-fact for each of the Sellers)

/s/ Don P. Millican

Name: Don P. Millican

TARGET:

KAISER-WHITING, LLC

By Kaiser-Francis Management Company, L.L.C., its Manager

/s/ Don P. Millican

Name: Don P. Millican

Title: President

EXHIBIT 21.1

Subsidiaries of the Partnership

The following are wholly owned subsidiaries of Energy 11, L.P.:

Energy 11 Operating Company, LLC (Formed in Delaware)
Energy 11 Acquisitions, LLC (Formed in Delaware)

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13a-14(a)/15D-14(a)

I, Glade M. Knight, certify that:

1. I have reviewed this Annual Report on Form 10-K of Energy 11, L.P. (the "registrant");

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)) 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 (or persons performing the equivalent functions):

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

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

Date: March 3, 2017

By:	/s/ Glade M. Knight
Name:	Glade M. Knight
Title:	General Partner, Chief Executive Officer (Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO RULE 13a-14(a)/15D-14(a)

I, David S. McKenney, certify that:

1. I have reviewed this Annual Report on Form 10-K of Energy 11, L.P. (the "registrant");

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)) 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 (or persons performing the equivalent functions):

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

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

Date: March 3, 2017	By:	/s/ David S. McKenney
	Name:	David S. McKenney
	Title:	General Partner, Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT 32.1

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

This certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and accompanies the Annual Report on Form 10-K (the "Form 10-K") for the year ended December 31, 2016 of Energy 11, L.P. (the "Company"). I, Glade M. Knight, the Chief Executive Officer of the Company, certify that, based on my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company as of and for the periods covered in this report.

Date: March 3, 2017	By:	/s/ Glade M. Knight
	Name:	Glade M. Knight
	Title:	General Partner, Chief Executive Officer (Principal Executive Officer)

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

EXHIBIT 32.2

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

This certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and accompanies the Annual Report on Form 10-K (the "Form 10-K") for the year ended December 31, 2016 of Energy 11, L.P. (the "Company"). I, David S. McKenney, the Chief Financial Officer of the Company, certify that, based on my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company as of and for the periods covered in this report.

Date: March 3, 2017	By:	/s/ David S. McKenney
	Name:	David S. McKenney
	Title:	General Partner, Chief Financial Officer (Principal Financial and Accounting Officer)

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

EXHIBIT 99.1

ENERGY 11, LP

5815 N. WESTERN AVENUE
OKLAHOMA CITY, OK 73118

RESERVES AND ECONOMIC EVALUATION
YEAR END 2016 RESERVES

NON-OPERATED ASSETS LOCATED WITHIN THE SANISH OIL FIELD LOCATED IN MOUNTRAIL COUNTY, NORTH DAKOTA

EFFECTIVE: JANUARY 1, 2017
SEC PRICING

Prepared: January 12, 2017

By: John Paul (J.P.) Dick, P.E.
Candace Cantrell, P.E.

January 12, 2017

ENERGY 11, LP
5815 N. Western Avenue
Oklahoma City, OK 73118

Re: Reserve & Economic Evaluation
Non-Operated Assets in the Sanish Oil Field
Mountrail County, North Dakota
Year End 2016 Reserves – SEC Price

EXECUTIVE SUMMARY

An engineering and economic evaluation was prepared for oil and gas reserves located in the Williston Basin Sanish Field in Mountrail County, North Dakota in which Energy 11, LP owns a working and/or royalty interest. The oil and gas reserves associated with these properties were evaluated and classified as Proved Reserves in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC). The Proved reserves include two hundred sixteen (216) horizontal Proved Developed Producing (PDP) wells and fifty-eight (58) Proved Undeveloped (PUD) horizontal locations targeting the Bakken Shale and Three Forks formation in multiple sections/units. The Non-Proved reserves include sixty-one (61) Probable Undeveloped (PROB) locations. Remaining reserves, future cashflow, and present worth values were calculated as of January 1, 2017. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Energy 11.

The reserves and economics were determined using SEC YE2016 pricing as of January 1, 2017. **Table 1** summarizes the estimated net reserves and future net revenue (cashflow), discounted and undiscounted, to the Energy 11 interest in these properties.

Table 1 - Net Reserve and Economic Report Summary

Reserve Category	# Wells	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Net Cashflow ($M)	PV 10% ($M)
Proved	**274**	**8,791**	**9,967**	**1,218**	**155,028**	**60,946**
PDP	216	4,748	5,163	631	89,934	46,597
PUD	58	4,042	4,804	587	65,094	14,349
Non-Proved	**61**	**4,110**	**4,821**	**589**	**59,671**	**7,596**
PROB	61	4,110	4,821	589	59,671	7,596
Grand Total	**335**	**12,901**	**14,788**	**1,807**	**214,699**	**68,542**

ECONOMIC EVALUATION

FUTURE INCOME

Future net revenue in this report includes deductions for state production taxes. Future net cashflow is after deducting state production taxes, future capital investments, and lease operating expenses but before consideration of any state and/or federal income taxes. For purposes of this evaluation, future capital investments include costs for drilling, completing, and equipping new wells. Abandonment costs at the end of well life for each well have been included in this evaluation. The future net cashflow has not been adjusted for any outstanding loans that may exist, cash on hand, or undistributed income. Future net cashflow has been discounted at an annual rate of ten percent (10%) to determine its "present worth." The present worth is shown to indicate the effect of time on the value of money. Future net revenue (cashflow) presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties evaluated.

INTERESTS

Well and leasehold interests were provided by Energy 11 and were assumed to be correct. The non-operated interests average approximately 11% working interest and 9% net revenue interest.

PRODUCT PRICING

Per SEC rules, the SEC pricing is determined by calculating the unweighted arithmetic average of the first-day-of-the-month NYMEX oil and gas pricing for the prior twelve calendar months (January 2016 through December 2016) to the date of evaluation. All prices are held constant throughout the lives of the properties. For year-end 2016, the unweighted arithmetic average NYMEX (Cushing) oil price is 42.75 $/bbl and the average NYMEX (Henry Hub) natural gas price is 2.48 $/MMbtu. Prices were adjusted for quality, basis, energy content, transportation fees and other market differentials based on an analysis of revenue data.

Differentials to NYMEX pricing were calculated by examining revenue statements and financial information to determine deductions or increases to oil and gas prices due to Btu, differentials, NGLs, processing, transportation, and/or contract terms. The pricing adjustments and differentials include the following:

Oil Price differential of -6.50 $/bbl
Natural Gas Liquids (NGL) determined using 11% of Oil Price
Residue Natural Gas differential of -2.86 $/Mcf
Natural Gas shrink of 19%
Natural Gas Liquid Yield of 99 bbl/MMcf wet gas

EXPENSES

An expense model was provided by Energy 11 to model the actual well life expense changes for all wells and undeveloped locations. Expenses were not escalated.

25,000 $/month for 1.5 years then…
20,000 $/month for 1.5 years then…
15,000 $/month for 1 year then…
12,000 $/month for 1 year then…
10,000 $/month for 3 years then…
7,500 $/month for 5 years then…
6,800 $/month until ECL

FUTURE WELL INVESTMENTS

Capital expenses for the future locations were estimated to be 6.4 MM$/well, which is consistent with recent, actual industry drilling and completion costs for wells within the prospective area. Capital timing for future development work was provided by Energy 11. Pinnacle cannot be responsible for capital costs that exceed or are less than these estimates.

RESERVE DETERMINATION

RESERVE DISCUSSION

Remaining recoverable reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty depending primarily on the amount of reliable geologic and engineering (production, pressure) data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty is conveyed by classifying reserves as Proved (highly certain) or Non-Proved (less certain). The estimated reserves and revenues shown in this report were determined by SEC standards for Proved Developed Producing (PDP) wells, Proved Non-Producing (PNP) wells and Proved Undeveloped (PUD) locations.

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs with defined limits and under current economic conditions, operating methods, and government regulations. Changes in any of these variables could materially change the reserves actually recovered.

Proved reserves are further classified as Proved Developed Producing (PDP) which is assigned to wells with sufficient production history to allow material balance and decline curve analysis to be the primary methods of estimation. PDP reserves are the most reliable reserves, generally with a high degree of confidence (>90%) that actually recovered quantities will equal or exceed published reserve estimates.

Proved Developed Non-Producing (PNP) reserves include zones that have been penetrated by drilling but have not produced or have not produced in sufficient quantities to allow material balance or decline curve analysis with a high degree of confidence. This category includes Proved Developed Behind-Pipe (PDBP) zones and tested wells awaiting production equipment (PNP).

Proved Undeveloped (PUD) reserves are those quantities of petroleum that are estimated to be recovered from undrilled acreage (locations) in a continuous portion of the Proved Developed reservoir as defined by directly offsetting PDP wells and geological interpretations. The Proved Undeveloped and Non-Producing wells are forecasted based on geological data presented, volumetric calculations, and analog comparisons to existing completions.

Non-Proven (Probable and Possible) reserves appear to have engineering and geologic merit and have been determined to have over 50% (Probable) or over 10% (Possible) likelihood to be commercially productive, but lack some aspect by definition to be considered proven, such as proximity to commercial production, production methods not proven for a certain geological or production application, or other geological or engineering deficiency.

GENERAL

The reserves and values included in this report are estimates only and should not be construed as being exact quantities. The reserve estimates were performed using accepted engineering practices and were primarily based on historical rate decline analysis for existing producers. When possible and practical, volumetric calculations and analogies were integrated into the reserve estimates. As additional pressure and production performance data becomes available, reserve estimates may increase or decrease in the future. The revenue from such reserves and the actual costs related may be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves included in this report and the costs incurred in recovering such reserves may vary from the price and cost assumptions referenced. Therefore, in all cases, estimates of reserves may increase or decrease as a result of future operations. We consider all assumptions, data, and procedures utilized in this report appropriate for the purpose of this report.

In evaluating the information available for this analysis, items excluded from consideration were all matters as to which legal or accounting interpretation, rather than engineering interpretation, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and such conclusions necessarily represent only informed professional judgments.

Pinnacle Energy Services, L.L.C. is an established petroleum engineering consulting firm. We hereby confirm that neither this firm, its affiliates, nor any of its employees, members, officers, or directors has, or is committed to acquire any interest, directly or indirectly, in the properties covered by this report, in any partnership, any general partner of the partnerships, nor is this firm or any employee, member or officer, or director thereof otherwise affiliated with any partnership or any such general partner. This report was completely independently prepared by Pinnacle Energy Services L.L.C. and our engagement and payment for services in connection with this report is independent of the outcome and not on a contingent basis.

The titles to the properties have not been examined nor has the actual degree or type of interest owned been independently confirmed. A field inspection of the properties is not usually considered necessary for the purpose of this report.

All information reviewed and utilized will be retained and is available for review by authorized parties at any time. Information used to prepare the evaluation was provided by Energy 11, LP, and was supplemented by public and in-house data. Pinnacle Energy Services, L.L.C. can take no responsibility for the accuracy of the data used in the analysis, whether gathered from public sources or otherwise.

Pinnacle Energy Services, LLC

/s/ John Paul Dick	/s/ Candace Cantrell
John Paul (J.P.) Dick, P.E.	Candace Cantrell, P.E.
Petroleum Engineer	Petroleum Engineer