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, 2015**

OR

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

COMMISSION FILE NUMBER: **000-1581552**

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: None

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

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 o No þ

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 þ No o

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 þ No o

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. þ

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	o	Accelerated filer	o
Non-accelerated filer (Do not check if a smaller reporting company)	o	Smaller reporting company	þ

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

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 up to $20. The aggregate market value of the registrant's limited partnership interests held by non-affiliates of the registrant as of June 30, 2015, was $0.

As of March 28, 2016, the Partnership had 5,586,294 Common Units outstanding.

ENERGY 11, L.P.

FORM 10-K

Index

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;
- 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. As of March 28, 2016, we had 5,586,294 common units outstanding.

As of December 31, 2015, we own 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 purchase closed on December 18, 2015. For this reason, our 2015 operating results reflect only the 14-day period during 2015 that we owned these properties. See “*2015 Acquisition*” below.

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 will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States, and to develop those properties.

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.

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 "Manager") to provide management and operating services regarding substantially all aspects of the Partnership. The Manager is an indirect, wholly-owned subsidiary of American Energy Partners, L.P. The Manager is not an affiliate of the Partnership or the General Partner.

Under the Management Agreement, the Manager will provide management and other services to the Partnership including the following:

- Identifying producing and non-producing properties that the Partnership may consider acquiring, and assisting in evaluation, contracting for and acquiring these properties and managing the development of these properties;
- Operating, or causing one of its affiliates to operate, on the Partnership's behalf, any properties in which the Partnership interest in the property is sufficient to appoint the operator;
- Overseeing the operations on properties the Partnership acquires that are operated by persons other than the Manager, including recommending whether the Partnership should participate in the development of such properties by the operators of the properties; and
- Assisting in establishing cash management and risk management programs.

The Management Agreement provides that the Partnership will direct the services provided to it under the Management Agreement, and that the Manager will determine the means or method by which those directions are carried out. The Management Agreement provides that the Manager will conduct the day-to-day operations of the Partnership's business as provided in budgets that the Manager will prepare and the Partnership will have the right to approve. The Management Agreement also contains a list of activities in which the Manager will not engage without the Partnership's prior approval.

The Manager will be reimbursed for certain costs directly related to the Partnership and will be paid a monthly general and administrative expense compensation amount ("Monthly G&A Expense Amount") at an annual rate that will be 1.75% of the net proceeds from the sale of common units, less commissions, marketing fee and offering and organization expense, plus the amount of outstanding indebtedness, which is referred to as the reimbursement base, for the first six months following the initial closing. Thereafter, the Monthly G&A Expense Amount will be at an annual rate of 3.5% of the reimbursement base and will reduce to an annual rate of 2% of the reimbursement base over time. In addition, pursuant to the Partnership Agreement, concurrently with the initial closing of the sale of common units, 100,000 class B units were issued to an affiliate of the Manager.

Subject to certain exceptions, the Management agreement will remain in effect as long as the Partnership holds any assets.

To date the Partnership has only non-operated assets which may impact the amount and type of duties needed from the manager.

The Management Agreement is terminable by us if: (i) we sell all or substantially all of our assets; (ii) there is a change in control and the Manager is no longer controlled by Mr. McClendon or his immediate family; (iii) Mr. McClendon, the Manager's key employee, ceases to be employed by the Manager and we do not approve of a proposed replacement of such key employee; (iv) the Manager becomes subject to bankruptcy proceedings; (v) the Manager materially breaches its obligations under the Management Agreement and does not cure the breach within 60 days of its receipt of notice of the breach; or (vi) the Manager or its affiliates defraud us or steal or misappropriate any of our assets and such circumstances have not been cured as provided in the Management Agreement. We may also terminate the Management Agreement if the Manager fails to recommend to us one or more acquisitions of producing or non-producing oil and gas properties that meet our acquisition parameters and are reasonably capable of consummation at any time that we have an aggregate of at least $100 million consisting of capital contributions received by us and which have not been spent by us, and all available borrowings under our credit facility, in each case, that have not been reserved by us for any acquisitions, development operations or other expenses, which we refer to as Unallocated Funds, for a period of 60 consecutive days.

For the year ended December 31, 2015, the Partnership incurred fees of approximately $253,000 and estimated reimbursable costs of approximately $200,000 under the management agreement.

On March 2, 2016, Aubrey McClendon, who controlled the Manager, was killed in a car accident. We do not believe this will cause any interruption in our existing operations, since all of the Partnership's assets are operated by Whiting Petroleum Corporation, an independent third party ("Whiting").

2015 Acquisition

On September 15, 2015, we entered into an Interest Purchase Agreement by and among Kaiser-Whiting, LLC and the owners of all the limited liability company interests therein (the "Sellers"), for the purchase of the Sanish Field Assets. We completed the purchase transaction on December 18, 2015. Prior to this acquisition, we owned no oil or natural gas assets. The Sanish Field Assets currently constitute all of our oil and gas properties.

The Sanish field is part of the Greater Williston Basin where industry activity is focused on development of the prolific Bakken Shale formation. Whiting, a publicly traded oil and gas company, operates the assets on behalf of the Partnership and other working interest owners. The Bakken Shale and its close geologic cousin, the Three Forks Shale, are found in the Williston Basin, centered in North Dakota. The Bakken Shale in the Williston Basin is one of the largest oil fields in the U.S., covering an area of approximately 17,500 square miles. While oil has been produced in North Dakota from the Williston Basin since the 1950s, it is only since 2007 through the application of horizontal drilling and hydraulic fracturing technologies that the Bakken has seen an increase in production activities.

Under the Purchase Agreement, we agreed to pay a cash purchase price for the Sanish Field Assets, consisting of (i) an initial $160 million, payable at closing subject to customary adjustments, (ii) an aggregate of $2 million, payable in equal amounts on December 31, 2016 and December 31, 2017 and (iii) a contingent payment of up to $95 million. The contingent payment was to provide a means for a sharing between the Partnership and the Sellers to the extent the NYMEX current five-year strip oil price for WTI at December 31, 2017 is above $56.61 (with a maximum of $89.00) per barrel. The contingent payment will be calculated as follows: if on December 31, 2017 the average of the monthly NYMEX:CL strip prices for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022 (the "Measurement Date Average Price") is greater than $56.61, then the Sellers will be entitled to a contingent payment equal to (a) (i) the lesser of (A) the Measurement Date Average Price and (B) $89.00, minus (ii) $56.61, multiplied by (b) 586,601 Bbls per year for each of the five years from 2018 through 2022 represented by the contracts for the entire acquisition. The contingent consideration is capped at $95 million and is to be paid on January 1, 2018.

In connection with the closing of the acquisition on December 18, 2015, we entered into a First Amendment to Interest Purchase Agreement, which changed the method of payment of the initial $160 million of the purchase price. Under the terms of the First Amendment, we paid the Sellers $60 million in cash at the closing, and delivered a secured promissory note payable to the Sellers in the original principal amount of $97.5 million (the "Seller Note"). See "*Financing for the 2015 Acquisition*" below. The purchase price was also net of estimated operating cash flow of approximately $2.5 million from September 15, 2015 through December 31, 2015. The First Amendment provides that so long as the Partnership is not in default under the Seller Note, in lieu of our obligation to make the contingent payment, we will have a one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to pay the Sellers $5 million in full satisfaction of the contingent payment obligation, by either paying to the Sellers $5 million at the time of election or by increasing the amount of the Seller Note by $5 million.

Financing for the 2015 Acquisition

The Seller Note bears interest at 5% per annum and is payable in full no later than September 30, 2016 ("Maturity Date"). Subject to the Partnership's compliance with the conditions set forth in the Seller Note and below, the Partnership shall have the right to extend the Maturity Date to March 31, 2017. The Partnership's right to extend the Maturity Date is subject to the satisfaction of the following conditions: (i) the Partnership must deliver to Seller written notice of the election to extend the Maturity Date no later than September 1, 2016, (ii) the Partnership shall pay to Seller by September 30, 2016, an extension fee equal to 0.5% of the outstanding principal balance outstanding at that date, (iii) during the extension period and until the Seller Note is paid in full, in cash, the interest rate on the outstanding principal amount of the Seller Note shall bear interest at the fixed rate of 7.0% per annum, (iv) the outstanding principal amount of the Seller Note as of September 1, 2016 shall not be in excess of $60 million, and (v) both at the time of the delivery of the extension notice and as of September 30, 2016, no event of default shall exist under the Seller Note or any collateral document. There is no penalty for prepayment of the Seller Note. Payment of the Seller Note is secured by a mortgage and liens on all of the Sanish Field Assets in customary form. If the Partnership has not fully repaid all amounts outstanding under the Seller Note on or before June 30, 2016, the Partnership must also pay a deferred origination fee in an amount equal to $250,000.

Interest is due monthly on the last day of each month while the Seller Note remains outstanding. In addition to interest payments on the outstanding principal balance of the Seller Note, the Partnership must make mandatory principal payments monthly in an amount equal to 75% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the Seller Note is reduced to $60 million and 50% of the net proceeds the Partnership receives from the sale of its equity securities thereafter, until the Seller Note is paid in full. In addition, if the Partnership sells any of the property that is collateral for the Seller Note, the Partnership must make a mandatory principal payment equal to 100% of the net proceeds of such sale until the principal amount of the Seller Note is paid in full.

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 are required to approve any significant modifications, as well as any new significant related party transactions.

See further discussion in Note 7 titled "Related Parties" in Part II Item 8 of this Form 10-K.

Distributions

Prior to Payout, as defined below, all distributions made by the Partnership, if any, will be paid to holders of common units.

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, 35% to the holders of the Incentive Distribution Rights (held by the General Partner), 35% to the holders of the class B units (held by an affiliate of the Manager) and 30% to the managing dealer for our ongoing initial public offering of units as its contingent, incentive fee, until such managing dealer receives incentive fees equal to 4% of the gross proceeds of the public offering; and
- Thereafter, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the holders of the common units.

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.

Our Oil and Natural Gas Reserves

The table below summarizes our estimated net proved reserves as of December 31, 2015:

	As of December 31, 2015		
	Oil (MBbls)	**NGLS (MBbls)**	**Natural Gas (MMcf)**
Proved Reserves (1)			
Developed	5,603	962	3,966
Undeveloped	3,465	903	3,723
Total Proved Reserves	9,068	1,865	7,689

(1) Our proved reserves as of December 31, 2015 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, natural gas and NGL prices used in computing the Partnership's reserves as of December 31, 2015 were $50.28 per barrel, $2.59 per MMbtu, 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 MMbtu of natural gas and $9.77 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.

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 their current levels are below the average calculated for 2015. Sustained lower prices will cause the estimated quantities and present values of our reserves being reduced and may necessitate future write-downs.

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, 2015 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. The Partnership has no internal technical person responsible for overseeing the preparation of the reserves estimates by Pinnacle.

Our President and Manager work 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. They work with Pinnacle Energy to review properties and discuss the methods and assumptions used by Pinnacle Energy in their preparation of the year end reserve estimates. Our President and Manager also meet to review the methods and assumptions used by Pinnacle Energy in the preparation of year end reserve estimates, and assess them for reasonableness.

The Board of Directors of our General Partner also meet with our President and Manager 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 developed non-producing properties and for 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, 2015, we had proved undeveloped reserves ("PUDs") of approximately 5.0 MMBOE, or approximately 40% of total proved reserves.

Total PUDs at December 31, 2014 were 0 MMBOE. The following table reflects the changes in PUDs during 2015:

	MBOE
Proved undeveloped reserves, December 31, 2014	0
Proved undeveloped reserves acquired	4,988
Proved undeveloped reserves, December 31, 2015	4,988

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, 2015 are scheduled to be drilled within five years of the date they were initially recorded. Lower prices for oil and natural gas as seen in the recent decline 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 amount 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,		
	2015	2014	2013
Net production MBOE(1):			
Oil	21,937	-	-
Natural gas	3,065	-	-
Natural gas liquids	2,841	-	-
Total (MBOE)	27,843	-	-
Average sales price per unit:			
Oil (per Bbl)	$ 30.17	$ -	$ -
Natural gas (per Mcf)	1.47	-	-
Natural gas liquids (per Bbl)	5.29	-	-
Combined (per BOE)	25.28	-	-
Average costs per BOE:			
Lease operating expense	$ 5.35	$ -	$ -
Production and ad valorem taxes	3.32	-	-

(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, 2015, we had no commitments to provide a fixed quantity of oil or natural gas.

Drilling Activity

Since we have only owned assets since December 18, 2015 we have limited drilling activity.

As of December 31, 2015, we were drilling 1 gross (.1365 net) well.

Total Productive Wells

The following table sets forth information with respect to our ownership interest in productive wells as of December 31, 2015:

	December 31, 2015	
	Gross	Net
Oil wells:		
Sanish Field	215	23.5
Natural gas wells		
Sanish Field	-	-

Of the total well count for 2015, 0 gross wells (0 net) 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, 2015, 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, N.D.	37,537	4,278	-	-	37,537	4,278

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 leasehold acreage, both developed and undeveloped.

Undeveloped Acreage Expirations

The following table sets forth information with respect to our gross and net undeveloped oil and natural gas acreage under lease as of December 31, 2015, all of which is located in the United States, that will expire over the following three years by core area unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Sanish Field	-	-	-	-	-	-

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.

Competition is strong for attractive oil and natural gas properties and there can be no assurances that we will be able to compete satisfactorily when attempting to make acquisitions. In general, sellers of producing properties are influenced primarily by the price offered for the property, although a seller also may be influenced by the financial ability of the purchaser to satisfy post-closing indemnifications, plugging and abandoning operations and similar factors.

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. In addition, it is possible that we will acquire oil and gas properties that are subject to flooding, drought or tornados. 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 also lessen seasonal demand fluctuations.

Environmental, Health and Safety Matters and Regulation

Our operations will be 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 2014 to 2016 and recently renewed this enforcement initiative 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, we will 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 or operator 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 (including a bill introduced in the current Congressional session) 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 has commenced a wide-ranging study on the effects of hydraulic fracturing on drinking water resources and released a draft report in 2015.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where we acquire 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 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 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, EPA informed petitioners that it denied the TSCA section 4 request and in a letter dated November 23, 2011, 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, EPA has concluded that TSCA section 21 does not apply to requests for a TSCA section 8(c) data call-in. 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 EPA 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 acquire, 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, 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, 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 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

We will be 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 we organize and/or disclose information about hazardous materials used or produced in our 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. In March 2016, the first cargo of LNG from the lower 48 States of the U.S. is expected to be exported from an LNG export facility located in Louisiana. 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 proposed 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. The Manager provides management and other services to the Partnership under direction of the General Partner as provided in the Management Agreement.

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. Information on the website is not part of this report.

Item 1A. Risk Factors

Risks Related to an Investment in the Partnership

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

The Partnership was formed in 2013. It had no operations prior to the initial closing of its public offering in August 2015, and accordingly, has no direct costs and administrative costs associated with prior operations. In addition, the Partnership did not own any operating assets prior to the acquisition of the Sanish Field Assets. 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.

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.

We incurred significant seller secured financing indebtedness in connection with our Sanish Field Assets acquisition in December 2015. The note and mortgage instruments governing this indebtedness contain restrictions that could adversely affect our operations, our ability to make acquisitions and our ability to pay distributions to our unitholders.

The promissory note we executed for the benefit of the Sellers in connection with our Sanish Field Assets acquisition (the "Seller Note") bears interest at 5% per annum and is payable in full no later than September 30, 2016 (the "Maturity Date"). Subject to our compliance with the conditions contained in the Seller Note and the related collateral documents, we will have certain rights to extend the Maturity Date to March 31, 2017. Our right to extend the Maturity Date, however, is subject to the satisfaction of numerous conditions. See Item 7 — "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Oil and Natural Gas Properties Acquired*." Payment of the Seller Note is secured by a mortgage and liens on all of the Sanish Field Assets, having customary terms. If we have not fully repaid all amounts outstanding under the Seller Note on or before June 30, 2016, we must also pay a deferred origination fee in an amount equal to $250,000.

Interest is due monthly on the last day of each month while the Seller Note remains outstanding. In addition to interest payments on the outstanding principal balance of the Seller Note, we must make mandatory principal payments monthly in an amount equal to 75% of the net proceeds we receive from the sale of our equity securities until the principal amount of the Seller Note is reduced to $60 million, and 50% of the net proceeds we receive from the sale of our equity securities thereafter, until the Seller Note is paid in full. We can make no assurances that we will be successful receiving sufficient proceeds of future sales of our securities in our initial public offering.

Because the indebtedness under the Seller Note is secured by a mortgage on our Sanish Field properties, the Partnership could lose these properties through foreclosure or other proceedings, if it defaults on that indebtedness. If the Partnership defaults under the Seller Note, the interest rate under the Seller Note will increase and it is possible that the Partnership could become involved in litigation related to matters concerning its indebtedness under the Seller Note. Such litigation could result in significant costs.

The dedication of amounts of net proceeds we receive from subsequent sales of equity securities to repay the outstanding indebtedness under the Seller Note will reduce our cash available to make distributions to our unitholders, until the indebtedness is repaid. In addition, these and other credit arrangements we may enter into may have the effect of restricting our ability to obtain additional financing, make investments, lease equipment, sell assets, enter into commodity and interest rate derivative contracts and engage in further property acquisitions. Our ability to comply with the terms of these debt arrangements in the future is uncertain and will be affected by the levels of cash flow from our operations, additional equity sums we raise from sales of our units, and events or circumstances beyond our control. Our failure to comply with certain of the requirements of these debt instruments could result in an event of default under their terms, which, if such default continues beyond any applicable cure periods, could cause all of our existing indebtedness to be immediately due and payable.

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 financing proceeds. 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 and proceeds of borrowings.

Moreover, as a result of the Seller Note indebtedness we incurred in connection with the 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 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 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 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 and the Manager under the Management Agreement 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," regardless of the Partnership's success in acquiring, developing and operating properties. In addition, under the Management Agreement, the Manager will receive the Monthly G&A Expense Amount and reimbursements of costs for providing management, operating and other services to us. The fees and direct costs to be paid to the General Partner and to the Manager under the Management Agreement 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 "— Compensation and fees paid to the General Partner and its affiliates regardless of success of the partnership's activities will reduce cash distributions;"
- fees and reimbursements payable to the Manager under the Management Agreement and any operating agreement under which the Manager operates our properties;
- the amount of time following the initial closing and any subsequent closings that it takes the General Partner to identify and acquire oil and gas properties;
- repayment of borrowings;
- 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 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 our 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;
- affiliates of the owners of our General Partner have made investments in, loaned money to, and have business dealings with, entities affiliated with the Manager and expect to do so in the future; 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, the Manager, 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. In addition, under the Management Agreement, the Manager will receive the Monthly G&A Expense Amount plus reimbursements of costs for providing management, operating and other services to us. 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, Manager and the dealer manager will reduce the amount of cash distributions to investors.

The Chief Executive Officer and the Chief Financial Officer of the General Partner of the Partnership do not have prior experience in the oil and gas industry.

This is the first oil and gas partnership that the Chief Executive Officer and the Chief Financial Officer of the General Partner will manage as executive officers. You should consider an investment in the Partnership in light of the risks, uncertainties and difficulties frequently encountered by companies with executive officers with limited experience in the industry of the company they will manage. There are risks that the Chief Executive Officer and Chief Financial Officer of the General Partner may not make the same decisions with respect to the management of the Partnership that executives with significant experience in the oil and gas industry would make.

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 agreed to purchase 5,000 common units for $20.00 per unit upon the earlier of the date that 5,263,158 common units have been sold and the final termination date of the public offering. In addition, the partnership agreement does not restrict the ability of the Manager or 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, and any affiliates or employees of the Manager 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 Management Agreement

We will depend on the Manager to provide us services necessary to operate our business. If the Manager is unable or unwilling to provide these services, it would result in disruption in our business, which could have an adverse effect on our ability to make cash distributions to holders of our common units and service our debt obligations.

Under the Management Agreement, the Manager will agree to provide services to us such as land, geoscience, engineering, drilling operations, legal, information technology, information management, marketing, acquisitions and divestitures, accounting, human resources, office space, and other administrative, technical and executive services. The Manager will also agree to operate, or cause affiliates to operate, or oversee the operations of other parties employed to perform development, operational and maintenance service for our properties for us. If the Manager were to become unable or unwilling to provide such services, we would need to develop these capabilities internally or arrange for these services from another service provider. Developing the capabilities internally or retaining another service provider could have an adverse effect on our operations and consequentially our ability to make cash distributions to holders of our common units, and the services, when developed or retained, may not be of the same quality as provided to us by the Manager.

The Manager, which will manage our business under the Management Agreement, is a newly formed entity with limited operating history.

Although the management of the Manager has extensive experience in the oil and gas business, the Manager is a recently formed entity with limited operating history. You should consider the risks associated with reliance on a company that is in the early stages of its development. The failure of the Manager to successfully execute its business plan could have an adverse effect on its ability to perform under the Management Agreement, which could adversely affect our business and ability to make distributions.

Affiliates of the Manager will engage in other business activities in addition to managing our assets under the Management Agreement. Engaging in these activities could reduce the time that management of the Manager spends on our business, which could adversely affect our business and ability to make distributions.

Affiliates of the Manager will independently engage in the oil and gas business, including the acquisition, exploration, development and operation of oil and gas properties. Affiliates of the Manager have acquired oil and gas properties in the Southern Wolfcamp play area of the Central Permian Basin in West Texas, the Utica Shale and liquids rich Marcellus Shale areas in Ohio, Pennsylvania and West Virginia and the Woodford Shale in Central Northern Oklahoma and opportunities to acquire or develop midstream assets in the continental United States, and may acquire additional interests in properties that consist exclusively of properties that will not be operated by the Manager or any of its affiliates or in the Permian Basin, Utica Shale, Marcellus Share, Woodford Shale and other areas in the future.

The ability and intent of the Manager to manage and engage in other business activities that may be in competition with us presents risks to the Partnership, including:

- These competing activities may be more profitable to the Manager than managing our business under the Management Agreement, which could cause the Manager to spend more time on the competing activities;
- The agreements governing the Manager’s other investments may provide for a higher rate of compensation to the Manager, which may cause the Manager to direct investment opportunities to the other entities it manages, or take such opportunities for itself; and
- Engaging in these competing activities could cause management of the Manager to have less time and resources to devote to our business.

As a result, the competing activities of the Manager could have an adverse effect on our business and prospects.

The Manager will not be restricted from competing with us in the acquisition, development and divestiture of oil and gas properties, which may adversely affect our ability to identify and acquire, develop and dispose of oil and gas properties.

Affiliates of the Manager are and will remain engaged in the oil and gas business. The Manager will not be obligated to offer to us any business opportunities, including oil and gas properties we may desire to acquire, or drilling and completion rigs and other equipment that we may need to develop our properties. The Manager may favor its affiliates over us in making decisions regarding acquisition of oil and gas properties and equipment to develop properties, which may adversely affect the quality of the properties we acquire and our ability to develop those properties, which would adversely affect our ability to make distributions and the value of your investment in us. In addition, the Manager is not required to arrange for us to acquire any specific amount or type of properties. While, under certain circumstances, we may terminate the Management Agreement and cancel a portion of the class B units issued to an affiliate of the Manager if oil and gas properties for acquisition are not referred to us by the Manager when we have funds to invest, termination of the Management Agreement may be impractical for a number of reasons, including because we cannot find a replacement manager at an acceptable cost or at all.

The Manager has no assets or operations other than its activities under the Management Agreement. In addition, the Management Agreement limits our right to seek money damages from the Manager for breach of the Agreement unless the Manager is grossly negligent. If the Manager breaches its obligations to us, we will have recourse only to the assets of the Manager, which are not material.

The Manager is a recently formed entity with no assets and no operations other than its activities under the Management Agreement. In the Management Agreement, the Manager agrees to actively seek properties for us to acquire, to cause its affiliates to provide the personnel necessary to conduct our business, and to take other actions that are important to our success. The Management Agreement provides that the Manager will be liable to us for monetary damages only if the manager is grossly negligent or willful in its actions. In addition, the Manager is a newly formed entity with no material assets, and no business other than its activities under the Management Agreement. As a result, even if the Manager is determined to have breached the Management Agreement in a manner that is grossly negligent or willful, our ability to collect monetary damages will be limited by the assets of the Manager, which are not likely to be significant.

The Manager will not owe a fiduciary or similar duty to us. Holders of common units will not have any right to enforce the Management Agreement if a holder of common units were to believe that the Manager was in breach of the agreement. Our ability to sue the Manager for monetary damages is limited.

The Management Agreement provides that the Manager will act as a reasonably prudent operator in operating out properties under the Management Agreement. The Manager will not have a fiduciary or similar duty to us or our limited partners when it acts under the Management Agreement. The prudent operator standard is a standard developed in connection with oil and gas operations, and provides considerable discretion to the Manager in the operation of our properties, and limits our right of recourse for damages caused to us if the Manager acts in accordance with the prudent operator standard. A holder of common units generally will not have the right to cause us to seek to enforce the Management Agreement if the holder of common units believes the Manager has breached the agreement.

In addition, the Management Agreement provides that the Manager will not be liable to us for monetary damages, unless the conduct that led to the damages was grossly negligent or intentional misconduct. As a result, we will not be able to collect monetary damages caused by the Manager’s negligence, even if such negligence violated the standard of care set forth in the Management Agreement.

The Manager will be subject to conflicts of interest in operating our business arising out of the ownership of the Class B Units by an affiliate of the Manager.

Because the holder of the Class B Units does not receive distributions until Payout occurs, the Manager will be subject to conflicts of interest caused by the ownership of the Class B Units by an affiliate of the Manager. These conflicts may cause the Manager to recommend the acquisition or sale of properties, the conduct of operations or to take other actions that are more risky to the Partnership than would be the case if the affiliate of the Manager did not own the Class B Units in order to generate distributions for the Class B Units.

We may acquire interests in oil and gas properties in which an affiliate of the Manager also owns an interest. The Manager may make decisions with respect to its interest in these properties that are not in our best interest.

We may acquire interests in properties in which an affiliate of the Manager also owns or acquires an interest. Affiliates of the Manager will not be under any obligation to us with respect to their interest in these properties. The affiliate of the Manager could propose or consent to operations, or sell or farm-out the interests in the properties, without taking into consideration our distribution policies, financial resources or whether such action is otherwise consistent with our goals or financial resources.

We may acquire oil and gas properties from the Manager or its affiliates. Our General Partner and the Manager will be subject to conflicts of interest if we acquire properties from an affiliate of the Manager.

Our Partnership Agreement does not restrict our ability to acquire oil and gas properties from affiliates of the Manager. It is possible that the Manager will offer to us oil and gas properties it owns or are owned by affiliates of the Manager. The Manager will be subject to conflicts of interest in determining whether to offer such properties to us, the proposed purchase price for such properties and the terms of any purchase and sale agreement for the properties. The Manager has no fiduciary or other duty to the Partnership in making an offer to sell properties owned by it or its affiliates to the Partnership, and is not required to act in the best interests of the Partnership or holders of common units. In addition, because of prior dealings between the Manager and the owners of our General Partner, our General Partner may be subject to conflicts of interest in determining whether to acquire properties from the Manager, as well as the purchase price and the terms of any purchase and sale agreement. In making a decision to acquire a property from the Manager or an affiliate of the Manager, the General Partner will be obligated to act in good faith, which generally means the General Partner is required to act in a manner which it believes is in the best interests of the Partnership, but will owe no additional duty to the Partnership or the owners of common units. In addition, because the General Partner does not have the technical staff to evaluate oil and gas properties, it will be required to rely on third party consultants in conducting such evaluation. No assurances can be given that third party consultants selected by the General Partner to evaluate properties offered by the Manager or an affiliate of the Manager will have technical expertise similar to that of the Manager.

Under the terms of the Management Agreement, the Monthly G&A Reimbursement Amount paid to the Manager will be based on a percent of capital contributions from holders of common units plus outstanding indebtedness. The Partnership will rely on the Manager for advice on the appropriate amount of indebtedness, and the Manager will be subject to conflicts of interest in providing such advice. In addition, because of prior dealings between the affiliates of the Manager and the owners of the General Partner, the General Partner may be subject to conflicts of interest causing the Partnership to incur indebtedness.

As part of our business strategy, we plan to incur indebtedness to finance a portion of our activities. As part of its services under the Management Agreement, the Manager will provide advice to us regarding the appropriate level of indebtedness. Because the Monthly G&A Reimbursement Amount paid to the Manager will increase with the amount of our outstanding indebtedness, the Manager will be subject to conflicts of interest in providing such advice to us. The Manager has no fiduciary or other duty to the Partnership in advising on appropriate levels of indebtedness, and is not required to act in the best interests of the Partnership or holders of common units in providing such advice. In addition, because of prior dealings between the Manager and the owners of our General Partner, our General Partner may be subject to conflicts of interest in determining the appropriate levels of our indebtedness. In making a decision regarding indebtedness of the Partnership, the General Partner will be obligated to act in good faith, which generally means the General Partner is required to act in a manner which it believes is in the best interests of the Partnership, but will owe no additional duty to the Partnership or the owners of common units.

The Manager may be subject to conflicts of interest in managing our business under the Management Agreement.

The Manager may offer to sell to the Partnership oil and gas properties or other assets in which the Manager or an affiliate owns an interest or may offer to acquire oil and gas properties or other assets from the Partnership. The Manager is under no fiduciary or other duty to offer to buy or sell properties or other assets to us or from us at a fair or market price. Affiliates of the Manager provide comparable management services to an oil and gas program not affiliated with us that may compete with us and may agree to provide similar services to additional entities formed by the sponsor of such oil and gas program. Our General Partner will be required to determine whether the Partnership should acquire or sell properties or other assets from or to the Manager. Because the General Partner has limited technical resources with which to evaluate oil and gas properties and other assets, the General Partner may, but is not required to, retain on behalf of the Partnership technical, legal, land, operational and other consultants to assist the General Partner in its determination of whether to acquire or sell properties or assets from or to the Manager or its affiliates.

The Manager will be subject to conflicts of interest in deciding which properties to present to us for acquisition and which properties its affiliates will keep for their own account.

Under the Management Agreement, the Manager has agreed to identify onshore producing and non-producing oil and gas properties that we may consider acquiring. In this regard, we and our General Partner do not have any right of first refusal to acquire properties in the inventory of the Manager or its affiliates or other properties that come to the attention of the Manager, and it may be to the advantage of the Manager or an affiliate of the Manager to keep or acquire a property for its own account or present the property to independent third parties because of the prospective economic benefits, rather than present the property to us for acquisition. For example, because the Management Agreement limits the amount of compensation that may be received by the Manager from us with respect to the properties we acquire, it may be more advantageous for the Manager or an affiliate of the Manager to acquire and develop the property for its own account or with another third party, since doing so would not be subject to the limitations under the Management Agreement. Also, the drilling of wells on properties we acquire pursuant to the Management Agreement may provide the Manager or its affiliate(s) with offset drilling sites by allowing the Manager or such affiliate(s) of the Manager to determine, in part at our expense, the value of adjacent acreage owned by the Manager or affiliates of the Manager. In this regard, there is no restriction on the Manager or affiliates of the Manager owning developed or undeveloped acreage throughout the areas where our properties and wells will be situated. In addition, there is no restriction in the Management Agreement or elsewhere on the Manager or any affiliate of the Manager pursuing business opportunities for its own account.

If conflicts between our interests, on the one hand, and the interests of the Manager or any affiliate of the Manager for its own account, on the other hand, do arise, then such conflicts may be resolved to the advantage of the Manager or such affiliate because the Manager will have no fiduciary duty to us or our General Partner to resolve any such conflict in our favor.

If the Manager or its affiliate acts as operator of the Partnership's oil and gas properties, it will be entitled to receive overhead payments under the operating agreements, which overhead payments may result in a profit to the Manager or such affiliate.

We expect that substantially all of the properties we acquire will be subject to an existing operating agreement negotiated between the operator and other owners of the property. Operating agreements for oil and gas properties generally provide that the operator is entitled to a fixed overhead charge per well operated. The Management Agreement will provide that if the Manager or an affiliate operates our property, it will do so under the operating agreement in place when the property is acquired, if any. The Manager or such affiliate will be entitled to receive the overhead charges provided for in operating agreements in place at the time of the acquisition, regardless of amount, and the Partnership will not have the right to negotiate a different overhead charge.

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 post-closing of the acquisition of the Sanish Field Assets in order to retain our full interest therein.

In addition to the $160 million initial purchase price for the Sanish Assets, we anticipate that we will be obligated to invest an additional $75 million in drilling capital expenditures through 2020 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, to fund the anticipated capital expenditures needed to retain our full interest in these assets. We anticipate paying the contingent payment, which will only arise if oil prices increase significantly over the next few years, out of the proceeds of production from the assets acquired and from additional financing that should become available if oil prices rise. 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:

- that our strategy of acquiring oil and gas properties at attractive prices 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;
- the amount of oil, natural gas and natural gas liquids we produce;
- the prices at which we sell our production;
- our ability to acquire oil and natural gas properties at economically attractive prices;
- 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 of our General Partner and fees and reimbursements to the Manager; and
- the level of our interest expense, which depends on the amount of our 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 remain 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 our credit facility, which may adversely affect our ability to make cash distributions to holders of our common units and service our debt obligations.

If we are unable to find suitable prospects and properties, we may not be able to achieve our investment objectives or pay distributions.

Our ability to achieve our investment objectives and to pay distributions depends primarily upon our ability to acquire and develop oil and gas properties. Competition may reduce the number of suitable investment opportunities offered to us or increase the bargaining power of property owners seeking to sell. Additionally, disruptions in the credit markets have materially impacted the cost and availability of debt to finance oil and gas acquisitions in the past. A period in which there is a lack of available debt could result in a reduction of suitable investment opportunities and create a competitive advantage to other entities that have greater financial resources than we do. During such times, our ability to borrow monies to finance the purchase of, or other activities related to, oil and gas assets will be negatively impacted. If we acquire properties and other investments at higher prices or by using less-than-ideal capital structures, our returns will be lower and the value of our assets may decrease significantly below the amount we paid for the assets.

Also, the more common units we sell in the public offering, the greater our challenge will be to invest all of the net offering proceeds on attractive terms. We can give no assurance that we will be successful in identifying or acquiring suitable properties on financially attractive terms or that our objectives will be achieved. If we are unable to identify and acquire suitable properties promptly, we will hold the proceeds from the public offering in an interest-bearing account or invest the proceeds in short-term assets. If we continue to be unsuccessful in identifying and acquiring suitable properties, we may ultimately decide to liquidate. In the event we are unable to timely locate suitable properties, we may be unable or limited in our ability to pay distributions and we may not be able to meet our investment objectives.

We may experience delays in locating oil and gas properties to acquire, which could limit our ability to make distributions and lower the overall return on your investment.

We will rely on our General Partner and the oil and gas professionals affiliated with the Manager to identify suitable investments. To the extent that our General Partner and the oil and gas professionals employed by our General Partner or the Manager face competing demands on their time at times when we have capital ready for investment, we may face delays in locating suitable properties. Further, the more money we raise in the public offering, the more difficult it will be to invest the net offering proceeds promptly and on attractive terms. Therefore, the large size of the public offering and the continuing high demand for the types of oil and gas properties we desire to purchase increase the risk of delays in investing our net offering proceeds. Delays we encounter in the selection and acquisition or origination of income-producing properties would likely limit our ability to pay distributions to holders of our common units and lower their overall returns. Further, our oil and gas development activities on a property will typically take months or longer to complete. Therefore, holders of our common units could experience delays in receiving the cash distributions attributable to those particular properties.

Because we will depend on our General Partner and its affiliates to conduct our operations, and our General Partner has engaged the Manager under the Management Agreement to assist it in performing such operations, any adverse changes in the financial health of our General Partner or the Manager 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 our General Partner will depend in part on the services of the Manager under the Management Agreement, and possibly other third party operators, for the acquisition, development and operation of our properties. Both our General Partner and the Manager are recently formed, our General Partner has no prior operating history and our Manager has a limited operating history. Any adverse changes in the financial condition of the General Partner, the Manager or in our relationship with them could hinder its or their ability to successfully manage our operations.

Our loan is secured by a mortgage on the properties, which create risks of foreclosures and increased expenses.

The Partnership has obtained a loan that is secured by mortgages on its properties and the Partnership may obtain additional loans evidenced by promissory notes secured by mortgages on its properties. As of December 31, 2015, the Partnership had approximately $85 million outstanding on its loan. Because the loan is secured by a mortgage, the Partnership could lose that property through foreclosure if it defaults on that loan. If the Partnership defaults under its loan, its interest rate under the loan will increase and it is possible that it could become involved in litigation related to matters concerning the loan, and such litigation could result in significant costs. Additionally, defaulting under the loan may damage the Partnership's reputation as a borrower and may limit its ability to secure financing in the future. All of these factors could limit our ability to make distributions to our common unit holders.

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 the Manager, 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 and those of the Manager 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 conditions and results of operations and our ability to make cash distributions to holders of our common units and service our debt obligations.

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 a draft of a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. These 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 expect to 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. However, our price hedging strategy and future hedging transactions will be recommended by the Manager under the Management Agreement, and subject to the approval of our General Partner, which is not under an obligation to hedge a specific portion of our 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. Neither our General Partner nor the Manager will 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 distressed 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 financially distressed 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 by the distressed entity or entities. 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 may be unable to integrate successfully the operations of our future acquisitions and we may not realize all the anticipated benefits of acquisitions that we make in the future.

Integration of our acquisitions will be a complex, time consuming and costly process. Failure to successfully assimilate our future acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired properties, especially if the assets acquired are in a new geographic area;
- the risk that reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired properties;
- inability to obtain satisfactory title to the assets we acquire;
- the diversion of the management attention of our General Partner and the Manager from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever acquisitions are consummated, and we may experience unanticipated delays in realizing the benefits of an acquisition.

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 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 our 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.

We may be unable to compete effectively with larger companies and may not be able to implement new technology as efficiently as larger companies, which may adversely affect our ability to generate sufficient revenue and our ability to pay distributions to holders of our common units and service our debt obligations.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Our ability to acquire oil and gas properties in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only acquire properties, drill for and produce oil, natural gas and natural gas liquids, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the technical, accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive oil and natural gas properties. We may be often outbid by competitors in our attempts to acquire properties. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we are able to do the same. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use becomes obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

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 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 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 and service our debt obligations.

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. We 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, the Manager 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 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.

As long as we qualify as an emerging growth company, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting.

Our independent registered public accounting firm will not be required to provide an attestation report on the effectiveness of our internal control over financial reporting so long as we qualify as an emerging growth company, which may increase the risk that weaknesses or deficiencies in the internal control over financial reporting go undetected. Likewise, so long as we qualify as an emerging growth company, we may elect not to provide certain information, including certain financial information and certain information regarding compensation of executive officers, which we would otherwise have been required to provide in filings with the SEC, which may make it more difficult for investors and securities analysts to evaluate us.

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 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 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 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.

The Obama administration's budget proposals for fiscal year 2015 contain numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies. Among others, the provisions include: repeal of the deduction of IDC; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; and an increase in the amortization period for geological and geophysical costs of independent producers.

The passage of any legislation as a result of these proposals or any other similar 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 of these 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" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Oil and Gas Operations and — Results of Operations" 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 intention of raising up to $2,000,000,000 of capital, consisting of 100,263,158 common units. As of December 31, 2015, the Partnership had completed the sale of a total of 4,486,625 common units at $19.00 per common unit for total gross proceeds of $85,245,875 and proceeds net of selling commissions and marketing expenses of $80,131,123. As of March 15, 2016 the common units were held by approximately 1,660 unitholders. As of March 4, 2016 the Partnership had received subscriptions for all of the common units to be offered at $19.00 per unit. The public offering is being made through David Lerner Associates, Inc. (the "Managing Dealer") 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 Managing Dealer, the Managing Dealer receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Managing Dealer 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, 2015, the total contingent fee is approximately $3.4 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:

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							
	4,486,625	Units	$	19.00	per unit	$	85,245,875
	-	Units	$	20.00	per unit		-
Totals:	4,486,625	Units				$	85,245,875

Expenses of Issuance and Distribution of Units		
1. Underwriting commissions	$	5,114,733
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		1,844,361
Total Expenses of Issuance and Distribution of Common Shares		6,959,094
Net Proceeds to the Partnership	$	78,286,781
1. Purchase of oil, gas and natural gas liquids properties (net of debt, proceeds and repayment including interest and acquisition costs)	$	73,042,412
2. Deposits and other costs associated with potential oil, natural gas and natural gas liquids acquisitions		-
3. Repayment of other indebtedness, including interest expense paid		-
4. Investment and working capital		3,972,639
5. Fees and expenses of third parties		-
6. Other		-
7. Distributions		1,271,730
Total Application of Net Proceeds to the Partnership	$	78,286,781

Class B Units

Upon entering into the management agreement with the Manager on August 19, 2015, the Partnership issued 100,000 class B units to an affiliate of the Manager. 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 Managing Dealer, 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, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the Managing Dealer as its contingent, incentive fee until the Managing Dealer receives incentive fees equal to 4% of the gross proceeds of the offering of common units; and then
- Thereafter, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the holders of the common units.

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, 2015, the Partnership paid distributions of $0.510138 per common unit or $1,271,730.

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 intention of raising 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, 2015 the Partnership had sold a total of 4,486,625 common units for gross proceeds of $85.2 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 has entered into a management services agreement (the “Management Agreement”) with E11 Management, LLC (the “Manager”). The Manager provides management and other services to the Partnership under direction of the General Partner as provided in the Management Agreement.

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.

Oil and Gas Properties Acquired

On September 15, 2015, the Partnership through a wholly owned subsidiary, entered into an Interest Purchase Agreement ("Purchase Agreement") by and among Kaiser-Whiting, LLC and the owners of all the limited liability company interests therein (the "Sellers"), for the purchase of an 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 (collectively, the "Sanish Field Assets"). The Partnership closed on the purchase of the Sanish Field Assets on December 18, 2015.

Pursuant to the Purchase Agreement as amended by the First Amendment thereto, the purchase price for the Sanish Field Assets consisted of (i) $60 million in cash, subject to customary adjustments, (ii) an aggregate of $2 million, payable in equal amounts on December 31, 2016 and December 31, 2017, (iii) a promissory note in the amount of $97.5 million payable to Sellers (the "Seller Note") and (iv) a contingent payment of up to $95 million. The contingent payment will provide for a sharing between the Partnership and the Sellers to the extent the NYMEX current five-year strip oil price for WTI at December 31, 2017 is above $56.61 (with a maximum of $89.00) per barrel. The contingent payment will be calculated as follows: if on December 31, 2017 the average of the monthly NYMEX:CL strip prices for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022 (the "Measurement Date Average Price") is greater than $56.61, then the Sellers will be entitled to a contingent payment equal to (a) (i) the lesser of (A) the Measurement Date Average Price and (B) $89.00, minus (ii) $56.61, multiplied by (b) 586,601 bbls per year for each of the five years from 2018 through 2022 represented by the contracts for the entire acquisition. The contingent consideration is capped at $95 million and is to be paid on January 1, 2018. In addition, the First Amendment provides that so long as the Partnership is not in default under the Seller Note, in lieu of the Partnership's obligation to pay the contingent payment, the Partnership has the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to pay Sellers $5 million in full satisfaction of the contingent payment by paying to Sellers $5 million at the time of election or by increasing the amount of the Seller Note by $5 million.

Whiting Petroleum Corporation ("Whiting"), a publicly traded oil and gas company, is the operator of our properties on behalf of the Partnership and the other working interest owners in those properties.

The Partnership expects to invest approximately $3.0 million in capital expenditures during 2016 as long as oil, natural gas and NGL prices remain at or near their current depressed levels. Our capital expenditure plan has the flexibility to adjust, should the commodity price environment change. Reduced capital expenditures are anticipated to result in lower oil, NGL and natural gas production volumes in 2016.

Since the Partnership is not the operator of any of its oil and natural gas properties, it is extremely difficult for us to predict levels of future participation in the drilling and completion of new wells and their associated capital expenditures. This makes 2016 capital expenditures for drilling and completion projects difficult to forecast and current estimated capital expenditure could be significantly different from amounts actually invested.

Looking forward, the Partnership expects to fund overhead costs, capital additions related to the drilling and completion of wells primarily from cash provided by operating activities and cash on hand. Any excess cash (including cash from the net proceeds of sales of units in our public offering) is intended to be used to pay down the principal amount of the Seller Note in favor of the Sellers.

Financing

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 in the original principal amount of $97.5 million. The note bears interest at 5% per annum and is payable in full no later than September 30, 2016 ("Maturity Date"). Subject to the Partnership's compliance with the conditions set forth in the note, the Partnership shall have the right to extend the Maturity Date to March 31, 2017. The Partnership's right to extend the Maturity Date is subject to the satisfaction of the following conditions: (i) the Partnership must deliver to Seller written notice of the election to extend the Maturity Date no later than September 1, 2016, (ii) the Partnership must pay to Seller an extension fee equal to 0.5% of the outstanding principal balance outstanding at September 30, 2016,, (iii) during the extension period and until the note is paid in full, the interest rate on the outstanding principal of the note shall bear interest at the fixed rate of 7.0% per annum, (iv) the outstanding principal amount of the note as of September 1, 2016 may not be in excess of $60 million, and (v) both at the time of the delivery of the extension notice and as of September 30, 2016, no event of default shall exist under the note or any collateral document. There is no penalty for prepayment of the note. Payment of the note is secured by a mortgage and liens on all of the Sanish Field Assets in customary form. If the Partnership has not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership must also pay a deferred origination fee in an amount equal to $250,000.

Interest is due monthly on the last day of each month while the note remains outstanding. In addition to interest payments on the outstanding principal balance of the note, the Partnership must make mandatory principal payments monthly in an amount equal to 75% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the note is reduced to $60 million and 50% of the net proceeds the Partnership receives from the sale of its equity securities thereafter, until the note is paid in full. In addition, if the Partnership sells any of the property that is collateral for the note, the Partnership must make a mandatory principal payment equal to 100% of the net proceeds of such sale until the principal amount of the note is paid in full.

As of December 31, 2015, the outstanding balance on the note was $85.0 million.

Management Agreement

At the initial closing of the sale of common units, August 19, 2015, the Partnership entered into a management services agreement (the “Management Agreement”) with E11 Management LLC (the “Manager”) to provide management and operating services regarding substantially all aspects of the Partnership. See Note 8 titled “Management Agreement” in Part II Item 8 of this Form 10-K for a description of the Management Agreement and the Manager.

Results of Operations

The Partnership closed its minimum offering on August 19, 2015. The Partnership closed on its purchase of the Sanish Field Assets on December 18, 2015. As a result, the Partnership had less than two weeks of operations of those properties. Other than the payment of fees and expenses described herein, the Partnership had no other operations. Because the Partnership had no revenues in fiscal 2014, there is no comparison of our results of operations for the year ended December 31, 2015 to any of our results of operations for the year ended December 31, 2014, except as otherwise indicated below.

Oil, Natural Gas and NGL Sales

For the 14 days from December 18, 2015 to December 31, 2015, oil, natural gas and NGL sales were $703,806. The sale of crude oil was $661,769, which resulted in a realized price of $30.17 per BOE. The sale of natural gas was $27,000, which resulted in a realized price of $1.47 per MCF. The sale of NGLs was $15,037, which resulted in a realized price of $5.29 per BOE of production.

The oil, natural gas and NGL production resulted from the Partnership’s acquisition of producing properties in the Sanish Field in North Dakota and the associated horizontal wells on that leasehold.

Operating Costs and Expenses

Lease Operating Expenses (LOE)

For the 14 days from December 18, 2015 to December 31, 2015, LOE was $149,072. LOE costs per BOE of production were $5.35.

Gathering and Processing Expenses

For the 14 days from December 18, 2015 to December 31, 2015, gathering and processing fees were $16,689. Gathering and processing costs per BOE of production were $0.60.

From time to time, operations will be incurred on a producing well to restore or increase production. For the 14 days from December 18, 2015 to December 31, 2015, workover expenses were $1,450. Workover expenses per BOE of production were $0.05.

Production Taxes

North Dakota’s oil and gas tax structure is comprised of two main taxes: the production tax and the extraction tax. The extraction tax rate was 6.5% of the gross value until December 31, 2015. Beginning January 1, 2016, the extraction tax rate decreased to 5% of the gross value at the well. This rate can increase to 6% if the high-price trigger is in effect. The production tax is 5%.

Our production taxes for the 14 days from December 18, 2015 to December 31, 2015 were $74,460. Production taxes per BOE of production were $2.67.

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. Our DD&A for the 14 days of production from December 18, 2015 to December 31, 2015 was $392,084.

Management Fees

Fees incurred under the management agreement with the Manager for the year ended December 31, 2015 were $252,524.

Acquisition Costs

Costs related to the acquisition of the Sanish Field assets for the year ended December 31, 2015 were $313,366. These costs include legal, accounting and due diligence associated with the purchase.

General and Administrative Costs

General and administrative costs for the year ended December 31, 2015 were $745,884 and include primarily accounting and legal fees, consulting fees and cost reimbursements to our Manager. For the year ended December 31, 2014, we incurred general and administrative expenses of $163,595.

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 oversee and review the Partnership's related party relationships and are required to approve any significant modifications, as well as any new significant related party transactions.

See further discussion in Note 7 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.

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 (i) the organizational limited partner withdrew its initial capital contribution of $990, and (ii) the General Partner received Incentive Distribution Rights (defined below). The General Partner 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.

As of August 19, 2015, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. As of December 31, 2015, the Partnership had completed the sale of a total of 4,486,625 common units at $19.00 per common unit for total gross proceeds of $85.2 million and proceeds net of offering costs including selling commissions and marketing expenses of $78.3 million. On March 4, 2016, the Partnership had received subscriptions for all 5,263,158 common units that the Partnership was offering at $19.00 per common unit. The Partnership is continuing the offering of the remaining common units at $20.00 per common unit in accordance with the prospectus. As of December 31, 2015, 95,776,533 common units remained unsold. The Partnership will offer common units until January 22, 2017, unless the offering is extended by the General Partner, provided that the offering will be terminated if all of the common units are sold before then.

The Partnership intends to continue to raise capital through its "best-efforts" offering of common units by David Lerner Associates, Inc. (the "Managing Dealer"). Under the agreement with the Managing Dealer, the Managing Dealer will receive a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Managing Dealer 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. 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.

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 or with respect to class B units and will not make any contingent, incentive payments to the Managing Dealer, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the 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 per unit outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per Unit, regardless of the amount paid for the Unit. If at any time the Partnership distributes to holders of 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, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the Managing Dealer as its contingent, incentive fee until the Managing Dealer receives incentive fees equal to 4% of the gross proceeds of the offering of common units; and then
- Thereafter, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the holders of the units.

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, 2015, the Partnership paid distributions of $0.510138 per unit or $1,271,730.

Since distributions to date have been funded with proceeds from the offering of units, the Partnership’s ability to maintain its current intended rate of distribution will be based on its ability to generate cash from operations resulting from its current acquisition. In addition, a significant portion of the proceeds from the sale of units during 2015 will be applied to the repayment of the outstanding principal amount of the indebtedness under the Seller Note, leaving less sums available for distribution to unitholders. As there can be no assurance of the Partnership’s ability to produce 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.

Liquidity and Capital Resources

The Partnership’s principal source of liquidity will be the proceeds of the “best-efforts” offering and the cash flow generated from properties the Partnership has acquired. In addition, the Partnership may borrow additional funds to pay operating expenses, distributions, make acquisitions or for other capital needs of the Partnership. In connection with the acquisition of the Sanish Field Assets, the Partnership executed the Seller Note in the original principal amount of $97,500,000. The Partnership intends to use proceeds from the offering to repay the Seller Note and its contingent payment and deferred payment obligations. As a result, until the Seller Note is repaid, the Partnership may not have available liquidity to fund additional acquisitions, capital improvements or distributions.

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, including appropriate escalators, 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.

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

There are two principal accounting practices to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner’s entitled share of the current period’s production (entitlement method). 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.

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.

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 balance sheets of Energy 11, L.P. (a Delaware limited partnership) (the "Partnership") as of December 31, 2015 and 2014, and the related statements of operations, partners' equity, and cash flows for the years then ended. 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 financial statements referred to above present fairly, in all material respects, the financial position of Energy 11, L.P. as of December 31, 2015 and 2014, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/S/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 28, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Managing General Partner of Energy 11, L.P.

We have audited the accompanying balance sheets of Energy 11, L.P. (the "Partnership") as of December 31, 2013 and July 9, 2013 (initial capitalization), and the related consolidated statement of operations, partners' equity and cash flows for the period July 9, 2013 (initial capitalization) through December 31, 2013. 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above presents fairly, in all material respects, the financial position of Energy 11, L.P. at December 31, 2013 and July 9, 2013 (initial capitalization), and the results of its operations and its cash flows for the period July 9, 2013 (initial capitalization) through December 31, 2013, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Richmond, Virginia

April 29, 2014

Energy 11, L.P.
Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
Assets		
Cash	$ 3,287,054	$ 94
Accounts Receivable:		
Oil, natural gas and natural gas liquids revenues	1,417,751	-
Acquisition post-closing receivable	1,556,530	-
Deferred offering costs and other assets	-	1,449,930
Total Current Assets	6,261,335	1,450,024
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization; December 31, 2015, $391,624; December 31, 2014, $0	158,895,191	-
Total Assets	$ 165,156,526	$ 1,450,024
Liabilities and Partners' Equity (Deficit)		
Note payable	$ 81,684,758	$ -
Due to general partner member	-	1,232,675
Contingent Consideration	4,743,752	-
Accounts payable and accrued expenses	3,449,442	390,000
Total Current Liabilities	89,877,952	1,622,675
Limited partners' interest (4,486,625 common units and 0 units issued and outstanding at December 31, 2015 and December 31, 2014, respectively)	75,280,301	(170,924)
General partner's interest	(1,727)	(1,727)
Class B Units (100,000 units and 0 units issued and outstanding at December 31, 2015 and December 31, 2014, respectively)	-	-
Total Partners' Equity (Deficit)	75,278,574	(172,651)
Total Liabilities and Partners' Equity (Deficit)	$ 165,156,526	$ 1,450,024

See accompanying notes to the financial statements.

Energy 11, L.P.
Consolidated Statements of Operations

	Year Ended December 31, 2015	Year Ended December 31, 2014	For the Period July 9, 2013 (initial capitalization) through December 31, 2013
Revenue			
Oil, natural gas and natural gas liquids revenues	$ 703,806	$ -	$ -
Expenses			
Lease operating expenses	149,072	-	-
Gathering and processing expenses	18,139	-	-
Production taxes	74,460	-	-
Management fees	252,524	-	-
Acquisition related costs	313,366	-	-
General and administrative expenses	745,884	163,595	10,056
Depreciation, depletion and amortization	392,084	-	-
Total expenses	1,945,529	163,595	10,056
Operating loss	(1,241,723)	(163,595)	(10,056)
Interest expense, net	321,093	-	-
Net loss	$ (1,562,816)	$ (163,595)	$ (10,056)
Basic and diluted net loss per common unit	$ (1.70)	$ -	$ -
Weighted average common units outstanding - basic and diluted	920,668	-	-

See accompanying notes to the financial statements.

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

	Limited Partners' Amount	Class B Units Amount	General Partner Amount	Total Partners' Equity/(Deficit)
Initial Capitalization July 9, 2013	$ 990	$ -	$ 10	$ 1,000
2013 Net Loss	(9,955)	-	(101)	(10,056)
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 to common units paid ($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

See accompanying notes to the financial statements.

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

	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	For the Period July 9, 2013 (initial capitalization) through December 31, 2013
Cash flow from operating activities:			
Net loss	$ (1,562,816)	$ (163,595)	$ (10,056)
Adjustments to reconcile net loss to cash used in operating activities:			
Depreciation, depletion and amortization	392,084	-	-
Non-cash fair value adjusted amortization	175,424	-	-
Changes in operating assets and liabilities:			
Increase in accounts receivable oil, natural gas and natural gas liquids	(703,806)	-	-
Accounts payable and accrued expenses	653,106	-	-
Due to general partner member	(158,641)	163,595	10,046
Net cash flow used in operating activities	(1,204,649)	-	(10)
Cash flow from investing activities			
Cash paid for acquisition of oil, natural gas and natural gas liquids properties	(60,000,000)	-	-
Net cash flow used in investing activities	(60,000,000)	-	-
Cash flow from financing activities			
Cash paid for offering costs	-	-	(896)
Net proceeds related to issuance of units	78,308,749	-	-
Distributions paid to limited partners	(1,271,730)	-	-
Payments on debt	(12,545,410)	-	-
Net cash flow provided by (used in) financing activities	64,491,609	-	(896)
Increase in cash and cash equivalents	3,286,960	-	(906)
Cash and cash equivalents, beginning of period	94	94	1,000
Cash and cash equivalents, end of period	$ 3,287,054	$ 94	$ 94
Interest paid	$ 173,711	$ -	$ -
Supplemental non-cash information:			
Accrued deferred offering costs and other assets	$ -	$ 1,181,442	$ 267,592
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	-	-

See accompanying notes to the financial statements.

Energy 11, L.P.
Notes to Financial Statements
December 31, 2015

(1) Partnership Organization

Energy 11, L.P., together with its wholly owned subsidiary, (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 "units") on a "best efforts" basis with the intention of raising up to $2,000,000,000 of capital, consisting of 100,263,158 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 units. The subscribers were admitted as Limited Partners of the Partnership at the initial closing.

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 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 units on a national securities exchange, and (iv) permit holders of units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the 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. Pursuant to the terms of a management agreement, the Partnership has engaged E11 Management, LLC (the "Manager"), to provide management and operating services regarding substantially all aspects of the Partnership's operations. David Lerner Associates, Inc. (the "Managing Dealer"), is the dealer manager for the offering of the units.

The Partnership's fiscal year ends on December 31.

(2) Summary of Significant Accounting Policies

Basis of Presentation

The accompanying 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 on-going best-efforts offering of units by David Lerner Associates, Inc., the managing underwriter, which receives a selling commission and a marketing expense allowance based on proceeds of the 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 shareholders' equity. Prior to the commencement of the Partnership's offering, these costs were deferred and recorded as prepaid expense. As of December 31, 2015, the Partnership had sold 4.5 million units for gross proceeds of $85.2 million and proceeds net of offering costs of $78.3 million.

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, including appropriate escalators, 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, 2015, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2015, 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 conducted within the contiguous United States (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 year ended December 31, 2015, relating to the Partnership’s asset retirement obligations:

		2015
Asset retirement obligations as of beginning of the year	$	-
Liabilities acquired on December 18, 2015 (Acquisition)		105,000
Accretion of discount (December 18, 2015 to December 31, 2015)		459
Asset retirement obligations as of end of the year	$	105,459

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 will be 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

There are two principal accounting practices to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner’s entitled share of the current period’s production (entitlement method). 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, 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 future crude oil, natural gas and NGL prices 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.

Earnings (Loss) Per Common Unit

Basic earnings (loss) per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted earnings (loss) per unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no units with a dilutive effect for the three months and twelve months ended December 31, 2015 and 2014. As a result, basic and diluted outstanding units were the same. The Class B Units and Incentive Distribution Rights are not included in earnings (loss) per common unit until such time that it is probable Payout (as discussed in Note 5) would occur.

Recent Accounting Standard

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) 2014-09, Revenue from Contracts with Customers, which will supersede nearly all existing revenue recognition guidance under GAAP. The standard’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard is effective for us on January 1, 2019. Early adoption is not permitted. The standard allows for either “full retrospective” adoption, meaning the standard is applied to all of the periods presented, or “modified retrospective” adoption, meaning the standard is applied only to the most current period presented in the financial statements. We are currently evaluating the transition method that will be elected and the impact, if any, on the Partnership’s financial statements.

In April 2015, the FASB issued an accounting standards update on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for reporting periods beginning after December 15, 2015, and it is not expected to have a material impact on the Partnership’s 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.

(3) Oil and Gas Investments

On September 15, 2015, the Partnership entered into an Interest Purchase Agreement ("Purchase Agreement") by and among Kaiser-Whiting, LLC and the owners of all the limited liability company interests therein (the "Sellers"), for the purchase of the Sanish Field Assets.

Pursuant to the Purchase Agreement as amended, the purchase price for the Sanish Field Assets consisted of (i) $60 million in cash, subject to customary adjustments, (ii) an aggregate of $2 million, payable in equal amounts on December 31, 2016 and December 31, 2017, (iii) a promissory note in the amount of $97.5 million payable to Sellers (the "Seller Note") and (iv) a contingent payment of up to $95 million. The contingent payment will provide for a sharing between The Partnership and Sellers to the extent the NYMEX current five-year strip oil price for WTI at December 31, 2017 is above $56.61 (with a maximum of $89.00) per barrel. The contingent payment will be calculated as follows: if on December 31, 2017 the average of the monthly NYMEX:CL strip prices for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022 (the "Measurement Date Average Price") is greater than $56.61, then the Sellers will be entitled to a contingent payment equal to (a) (i) the lesser of (A) the Measurement Date Average Price and (B) $89.00, minus (ii) $56.61, multiplied by (b) 586,601 bbls per year for each of the five years from 2018 through 2022 represented by the contracts for the entire acquisition. The contingent consideration is capped at $95 million and is to be paid on January 1, 2018. In addition, the First Amendment provides that so long as the Partnership is not in default under the Seller Note, in lieu of the Partnership's obligation to pay the contingent payment, the Partnership has the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to pay Sellers $5 million in full satisfaction of the contingent payment by paying to Sellers $5 million at the time of election or by increasing the amount of the Seller Note by $5 million.

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition date. The aggregate fair value of consideration transferred was $60.0 million in cash, $94.1 million in seller financed debt, $4.7 million in contingent consideration and $1.7 million in deferred purchase price payments, resulting in no goodwill or bargain purchase gain.

Proved oil, natural gas and NGL properties	$	159,217,000
Total assets acquired		159,217,000
Asset retirement obligations		105,000
Total liabilities assumed		105,000
Total fair value of net assets	$	159,112,000

The table above is based upon the original purchase price allocation and is subject to post-closing adjustments.

The Partnership paid $313,366 in transaction costs associated with 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 is a non-operator of the Sanish Field Assets, with Whiting, one of the largest producers in this basin, acting as operator.

The following unaudited pro forma financial information for the periods ended December 31, 2015 and 2014, has been prepared as if the acquisition of the Sanish Field Assets had occurred on January 1, 2014. 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	2014
	Unaudited	
Revenues	$ 26,831,257	$ 49,827,000
Net income	$ 2,336,675	$ 21,437,004

(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 in the original principal amount of $97.5 million. The note bears interest at 5% per annum and is payable in full no later than September 30, 2016 ("Maturity Date"). The Partnership's right to extend the Maturity Date to March 31, 2017 is subject to the satisfaction of the following conditions: (i) the Partnership must deliver to Seller written notice of the election to extend the Maturity Date no later than September 1, 2016, (ii) the Partnership must pay to Seller an extension fee equal to 0.5% of the outstanding principal balance outstanding at September 30, 2016, (iii) during the extension period and until the note is paid in full, in cash, the interest rate on the outstanding principal amount of the note will bear interest at the fixed rate of 7.0% per annum, (iv) the outstanding principal amount of the note as of September 1, 2016 shall not be in excess of $60 million, and (v) both at the time of the delivery of the extension notice and as of September 30, 2016, no event of default shall exist under the note or any collateral document. There is no penalty for prepayment of the note. Payment of the note is secured by a mortgage and liens on all of the Sanish Field Assets in customary form. If the Partnership has not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership must also pay a deferred origination fee in an amount equal to $250,000.

Interest is due monthly on the last day of each month while the note remains outstanding. In addition to interest payments on the outstanding principal balance of the note, the Partnership must make mandatory principal payments monthly in an amount equal to 75% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the note is reduced to $60 million and 50% of the net proceeds the Partnership receives from the sale of its equity securities thereafter, until the note is paid in full. In addition, if the Partnership sells any of the property that is collateral for the note, the Partnership must make a mandatory principal payment equal to 100% of the net proceeds of such sale until the principal amount of the note is paid in full.

As of December 31, 2015, the outstanding balance on the note was $85.0 million, the note has a carrying value of $81.7 million which approximates its fair market value.

(5) Capital Contribution and Partners' Equity

As of August 19, 2015, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. As of December 31, 2015, the Partnership had completed the sale of a total of 4,486,625 common units at $19.00 per common unit for total gross proceeds of $85.2 million and proceeds net of offering costs including selling commissions and marketing expenses of $78.3 million. On March 4, 2016, the Partnership had received subscriptions for all 5,263,158 common units that the Partnership was offering at $19.00 per common unit. The Partnership is continuing the offering at $20.00 per common unit in accordance with the prospectus. As of December 31, 2015, 95,776,533 common units remained unsold. The Partnership will offer common units until January 22, 2017, unless the offering is extended by the General Partner, provided that the offering will be terminated if all of the common units are sold before then.

The Partnership intends to continue to raise capital through its "best-efforts" offering of units by David Lerner Associates, Inc. (the "Managing Dealer"). Under the agreement with the Managing Dealer, the Managing Dealer will receive a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the units sold. The Managing Dealer 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 units sold ("Incentive Fee"). 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 units.

Upon entering into the management agreement with the Manager on August 19, 2015, the Partnership issued 100,000 class B units to an affiliate of the Manager. The class B units provide certain distribution rights described below.

Prior to "Payout," which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of 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 Managing Dealer, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the 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 Unit, regardless of the amount paid for the Unit. If at any time the Partnership distributes to holders of 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, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the Managing Dealer as its contingent, incentive fee until the Managing Dealer receives incentive fees equal to 4% of the gross proceeds of the offering of common units; and then
- Thereafter, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the holders of the units.

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.

Any payments under the Incentive Distribution Rights or Incentive Fee payable to the Managing Dealer will be accounted for as a reduction to Partner's Equity. If payment becomes probable the Partnership will estimate the value of the class B units and record an expense at that time.

For the year ended December 31, 2015, the Partnership paid distributions of $0.510138 per unit or $1,271,730.

(6) Fair Value of Financial Instruments

Fair value of the Partnership's financial instruments approximated carrying value at December 31, 2015.

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 12 months ended December 31, 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 contingent consideration. Within the valuation hierarchy, the Partnership measures the fair value of contingent consideration using Level 3 inputs. As of December 31, 2015, the fair value of contingent consideration was $4,743,752. The following table presents the contingent consideration required to be measured at fair value on a recurring basis as of December 31, 2015.

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
	$ -	$ -	$ -	$ -
Liabilities:				
Contingent consideration	$ -	$ -	$ 4,743,752	$ 4,743,752

The contingent consideration as discussed in Note 3 – "Oil and Gas Investments" is a liability that is measured at fair value on a recurring basis for which there is no available quoted market price. The inputs for this instrument are 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 the close date to be $12.5 million. As this is substantially greater than the $5.0 million option, a market participant would likely view the $5.0 million option as highly probable of being exercised and, therefore, value the contingent consideration at $5.0 million, discounted to the expected exercise date. The calculation of this liability is 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 is reflective of the Partnership's market adjusted borrowing rate of 11.15%.

The contingent consideration would increase with a reduction in the discount rate and decrease with an increase in the discount rate. Adjustments to the fair value of the contingent consideration are recorded in the statements of operations.

(7) 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 are required to approve any significant modifications, 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 year ended December 31, 2015 Mr. Merritt was paid $222,099.

Subsequent to completing 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.

During the year ended December 31, 2015, approximately $62,000 of general and administrative costs were incurred by the General Partner and reimbursed by the Partnership.

(8) Management Agreement

At the initial closing of the sale of common units, August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with E11 Management LLC to provide management and operating services regarding substantially all aspects of the Partnership. The Manager is an indirect, wholly-owned subsidiary of American Energy Partners, L.P. The Manager is not an affiliate of the Partnership or the General Partner.

Under the Management Agreement, the Manager will provide management and other services to the Partnership including the following:

- Identifying producing and non-producing properties that the Partnership may consider acquiring, and assisting in evaluation, contracting for and acquiring these properties and managing the development of these properties;
- Operating, or causing one of its affiliates to operate, on the Partnership's behalf, any properties in which the Partnership interest in the property is sufficient to appoint the operator;
- Overseeing the operations on properties the Partnership acquires that are operated by persons other than the Manager, including recommending whether the Partnership should participate in the development of such properties by the operators of the properties; and
- Assisting in establishing cash management and risk management programs.

The Management Agreement provides that the Partnership will direct the services provided to it under the Management Agreement, and that the Manager will determine the means or method by which those directions are carried out. The Management Agreement provides that the Manager will conduct the day-to-day operations of the Partnership's business as provided in budgets that the Manager will prepare and the Partnership will have the right to approve. The Management Agreement also contains a list of activities in which the Manager will not engage without the Partnership's prior approval.

To date, the Partnership has only purchased non-operated interests in oil and gas assets, which as a result may impact the amount and type of duties needed from the Manager.

The Manager will be reimbursed for certain costs directly related to the Partnership and will be paid a monthly general and administrative expense compensation amount ("Monthly G&A Expense Amount") at an annual rate that will be 1.75% of the net proceeds from the sale of common units, less commissions, marketing fee and offering and organization expense, plus the amount of outstanding indebtedness, which is referred to as the reimbursement base, for the first six months following the initial closing. Thereafter, the Monthly G&A Expense Amount will be at an annual rate of 3.5% of the reimbursement base and will reduce to an annual rate of 2% of the reimbursement base over time. In addition, pursuant to the Partnership Agreement, concurrently with the initial closing of the sale of common units pursuant to the public offering, 100,000 class B units were issued to an affiliate of the Manager.

Subject to certain exceptions, the Management Agreement will remain in effect as long as the Partnership holds any assets.

The Management Agreement is terminable by us if: (i) we sell all or substantially all of our assets; (ii) there is a change in control and the Manager is no longer controlled by Mr. McClendon or his immediate family; (iii) Mr. McClendon, the Manager's key employee, ceases to be employed by the Manager and we do not approve of a proposed replacement of such key employee; (iv) the Manager becomes subject to bankruptcy proceedings; (v) the Manager materially breaches its obligations under the Management Agreement and does not cure the breach within 60 days of its receipt of notice of the breach; or (vi) the Manager or its affiliates defraud us or steal or misappropriate any of our assets and such circumstances have not been cured as provided in the Management Agreement. We may also terminate the Management Agreement if the Manager fails to recommend to us one or more acquisitions of producing or non-producing oil and gas properties that meet our acquisition parameters and are reasonably capable of consummation at any time that we have an aggregate of at least $100 million consisting of capital contributions received by us and which have not been spent by us, and all available borrowings under our credit facility, in each case, that have not been reserved by us for any acquisitions, development operations or other expenses, which we refer to as Unallocated Funds, for a period of 60 consecutive days.

For the year ended December 31, 2015, the Partnership incurred fees of approximately $253,000 and estimated reimbursable costs of approximately $200,000 under the Management Agreement.

See Note 10 – "Subsequent Events" below.

(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, 2015 is as follows:

	2015
Producing properties	$ 90,167,047
Non-producing	69,119,768
	159,286,815
Accumulated depreciation, depletion and amortization	(391,624)
Net capitalized costs	$ 158,895,191

Costs Incurred

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

	2015
Property acquisition costs	$ 159,216,768
Development Costs	70,047
	$ 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, 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, 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.

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

	Proved Reserves			
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total (BOE)
January 1, 2015	-	-	-	-
Acquisition	9,089,252	1,866,775	7,705,802	12,240,327
Extensions, discoveries and other additions	-	-	-	-
Production (December 18 - December 31)	(21,937)	(2,841)	(18,392)	(27,843)
December 31, 2015	9,067,315	1,863,934	7,687,410	12,212,484

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, natural gas and NGL prices used in computing the Partnership's reserves as of December 31, 2015 were $50.28 per barrel, $2.59 per MMbtu, 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 MMbtu of natural gas and $9.77 per barrel of NGL.

	Proved Developed Reserves				Proved Undeveloped Reserves			
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total (BOE)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total (BOE)
December 31, 2015	5,602,387	961,147	3,964,052	7,224,210	3,464,928	902,787	3,723,358	4,988,274

The following details the changes in proved undeveloped reserves for 2015 (BOE):

Beginning proved undeveloped reserves	-
Acquisition	4,988,274
December 31, 2015	4,988,274

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.

	2015
Future cash inflows	$ 407,928,626
Future production costs	(136,547,001)
Future development costs	(37,640,024)
Future net cash flows	233,741,601
10% annual discount	(134,551,759)
Standardized measure of discounted future net cash flows	$ 99,189,842

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

	2015
Beginning of year	$ -
Changes resulting from:	
Acquisition of reserves	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(480,274)
Net change	99,189,842
End of year	$ 99,189,842

(10) Subsequent Events

In January 2016, the Partnership declared and paid $499,061, or $0.111233 per outstanding common unit, in distributions to its holders of common units.

In January 2016, the Partnership closed on the issuance of approximately 380,645 units through its ongoing best efforts offering, representing gross proceeds to the Partnership of approximately $7.2 million and proceeds net of selling and marketing costs of approximately $6.8 million.

In February 2016, the Partnership declared and paid $522,730, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In February 2016, the Partnership closed on the issuance of approximately 375,483 units through its ongoing best efforts offering, representing gross proceeds to the Partnership of approximately $7.1 million and proceeds net of selling and marketing costs of approximately $6.7 million.

On March 4, 2016 we had received subscriptions for all of the common units we were offering at $19.00 per common unit, 5,263,158 units and, consequently, all common units offered and sold after that date will be at $20.00 per common unit in accordance with the prospectus.

On March 2, 2016, Aubrey McClendon, who controlled our third party manager E11 Management, LLC was killed in a car accident. We do not believe this will cause any interruption in our existing operations, since as previously disclosed, substantially all of the Partnership's assets are operated by Whiting Petroleum Corporation, an independent third party.

In March 2016, the Partnership declared and paid $563,056, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In March 2016, the Partnership closed on the issuance of approximately 343,541 units through its ongoing best efforts offering, representing gross proceeds to the Partnership of approximately $6.9 million and proceeds net of selling and marketing costs of approximately $6.5 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, 2015 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, 2015. 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, 2015, 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, 2015 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, 2015.

Name	Age	Position
Glade M. Knight	72	*Chairman of the Board and Chief Executive Officer*
David S. McKenney	53	*Director and Chief Financial Officer and Secretary*
Anthony Francis “Chip” Keating III	36	*Director and Co-Chief Operating Officer*
Michael J. Mallick	53	*Director and Co-Chief Operating Officer*
Clifford J. Merritt	55	*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 the founder and Executive Chairman of Apple Hospitality REIT, Inc. and Chairman and Chief Executive Officer of Apple REIT Ten, Inc., each of which is a real estate investment trust, or REIT. Mr. Knight was the Chairman of the Board and Chief Executive Officer of Apple Hospitality Two, Inc., a lodging REIT, from 2001 until the company was sold to an affiliate of ING Clarion in May of 2007. Mr. Knight served in the same capacity for Apple Hospitality Five, Inc., another lodging REIT, from 2002 until the company was sold to Inland American Real Estate Trust, Inc. in October of 2007 and Apple REIT Six, Inc. from 2004 until the company was sold to BRE Select Hotels Corp in May of 2013. In addition, Mr. Knight served as Chairman and Chief Executive Officer of Cornerstone Realty Income Trust, Inc. until it merged with a subsidiary of Colonial Properties Trust in 2005. Following the merger in 2005 until April of 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. Apple Hospitality REIT, Inc. and Apple REIT Ten, Inc. each own hotels in selected metropolitan areas of the United States. 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. He has served on a 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 serves as Senior Advisor for Apple Hospitality REIT, Inc. and President of Capital Markets of Apple REIT Ten, Inc., each of which is a real estate investment trust. Mr. McKenney previously served as President of Capital Markets for Apple Hospitality REIT, Inc. Mr. McKenney was President of Capital Markets of Apple Hospitality Two, Inc., a lodging REIT, from 2001 until the company was sold to an affiliate of ING Clarion in May of 2007. Mr. McKenney served in the same capacity for Apple Hospitality Five, Inc., another lodging REIT, from 2002 until the company was sold to Inland American Real Estate Trust, Inc. in October of 2007 and Apple REIT Six, Inc. from 2004 until the company was sold to BRE Select Hotels Corp in May of 2013. 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 currently serves on the boards of Apple REIT Ten, Inc., The Children's Hospital Foundation and The Salvation Army. 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 just 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.

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 2000 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, 2015, 2014 and 2013. 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	2015	$ —	$ —	$ —	$ —
Chairman of the Board and Chief Executive Officer	2014	$ —	$ —	$ —	$ —
	2013	$ —	$ —	$ —	$ —
Clifford J. Merritt	2015	$ 222,009	$ —	$ —	$ 222,009
President					

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, subject to the General Partner’s oversight, the Manager provides us with management and operating services pursuant to the Management Agreement regarding substantially all aspects of our oil and gas operations. 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, 2015, 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 28, 2016 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 Management LLC, an indirect, wholly-owned subsidiary of American Energy Partners, L.P., owns all 100,000 class B units. The address of American Energy Partners, L.P. is 301 NW 63rd Street, Suite 600, Oklahoma City, Oklahoma 73116.

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 Suites 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 year ended December 31, 2015, approximately $62,000 of related party costs were incurred by 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 year ended December 31, 2015, Mr. Merritt was paid $222,099.

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, 2015. Grant Thornton was selected and appointed as our independent registered public accounting firm on March 18, 2015. For the period from July 9, 2013 (initial capitalization) to March 18, 2015, Ernst & Young LLP ("Ernst & Young") had served as our independent registered public accounting firm.

For the fiscal years ended December 31, 2014 and 2015, fees paid or payable to Grant Thornton and Ernst & Young for services performed in connection with the audit of the 2015 financial statements, the audit of the 2014 financial statements, reviews of the amended S-1s, SEC comment letters, issuance of consents and 2015 interim reviews are as follows:

Audit Fees

	Year Ended December 31, 2015	Year Ended December 31, 2014
Audit fees	$ 99,900	$ 81,925
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$ 99,900	$ 81,925

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 and Ernst & Young during fiscal 2015 and 2014 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) Reports of Independent Registered Public Accounting Firms

(ii) Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014

(iii) Consolidated Statements of Operations for the year ended December 31, 2015, the year ended December 31, 2014 and for the period July 9, 2013 (initial capitalization) through December 31, 2013

(iv) Consolidated Statements of Partners' Equity (Deficit) for the year ended December 31, 2015, the year ended December 31, 2014 and for the period July 9, 2013 (initial capitalization) through December 31, 2013

(v) Consolidated Statements of Cash Flows for the year ended December 31, 2015, the year ended December 31, 2014 and for the period July 9, 2013 (initial capitalization) through December 31, 2013

(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, 2015 (and are numbered in accordance with Item 601 of Regulation S-K).

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).
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	Escrow Agreement (incorporated by reference from Exhibit 10.1 to Amendment No. 6 to the Partnership's Registration Statement on Form S-1 filed on December 12, 2014).
10.2	Form of Management Services Agreement by and among E11 Management, LLC, E11 Incentive Holdings, LLC, Energy 11, L.P. and Energy 11 Operating Company, LLC, (incorporated by reference from Exhibit 10.2 to Amendment No. 4 to the Partnership's Registration Statement on Form S-1 filed on November 21, 2014).
10.3	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).

10.4	Consulting Agreement with Clifford Merritt (incorporated by reference from Exhibit 10.4 to Amendment No. 4 to the Partnership's Registration Statement on Form S-1 filed on November 21, 2014).
10.5	Secured Promissory Note dated December 18, 2015 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 December 21, 2015).
10.6	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).
16.1	Letter Agreement from Ernst & Young LLP to the Securities and Exchange Commission dated March 18, 2015 (incorporated by reference from Exhibit 16.1 to the Partnership's Current Report on Form 8-K filed with the SEC on March 19, 2015).
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 28, 2016

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 28, 2016
/s/ David S. McKenney David S. McKenney	Director, Chief Financial Officer (principal financial and accounting officer)	March 28, 2016
/s/ Anthony F. Keating III Anthony F. Keating III	Director, Co-Chief Operating Officer	March 28, 2016
/s/ Michael J. Mallick Michael J. Mallick	Director, Co-Chief Operating Officer	March 28, 2016

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)

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 28, 2016	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 28, 2016	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, 2015 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 28, 2016

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, 2015 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 28, 2016

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

120 W 3RD STREET, SUITE 220
FORT WORTH, TX 76102

RESERVES AND ECONOMIC EVALUATION
YEAR END 2015

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

EFFECTIVE: JANUARY 1, 2016
SEC PRICING

Prepared: January 22, 2016

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

PINNACLE ENERGY

January 22, 2016

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 2015 – 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). This report has been prepared for Energy 11's use in filing with the SEC. The Proved reserves include two hundred fifteen (215) horizontal Proved Developed Producing (PDP) wells, one (1) Proved Developed Non-Producing (PDNP) well, and forty-nine (49) Proved Undeveloped (PUD) horizontal locations targeting the Bakken Shale and Three Forks formation in multiple sections/units. Remaining reserves, future cashflow, and present worth values were calculated as of January 1, 2016. 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 dictated pricing as of January 1, 2016. **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	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Net Cashflow ($M)	PV 10% ($M)
Proved	**9,068**	**7,689**	**1,864**	**233,714**	**99,153**
PDP	5,513	3,871	939	145,644	74,647
PDNP	90	95	23	3,158	1,744
PUD	3,465	3,723	903	84,912	22,762

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 through December 2015) to the date of evaluation. All prices are held constant throughout the lives of the properties. For calendar year 2015, the unweighted arithmetic average NYMEX (Cushing) oil price is 50.28 $/bbl and the average NYMEX (Henry Hub) natural gas price is 2.59 $/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 -8.50 $/bbl
- Natural Gas Liquids (NGL) determined using 31.3% of Oil Price
- Residue Natural Gas differential of -0.25 $/Mcf
- Natural Gas shrink of 27%
- Natural Gas Liquid Yield of 177 bbl/MMcf wet gas
- Natural Gas BTU adjust of -37.5%

EXPENSES

Operating expenses for 2014 and 2015 were analyzed and utilized. An expense model was generated to model the actual well life expense changes for undeveloped locations and expenses were not escalated.

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 (PNPBP) 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.

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, American Energy Partners (“AEP”), 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
John Paul (J.P.) Dick, P.E.
Petroleum Engineer

/s/ Candace Cantrell
Candace Cantrell, P.E.
Petroleum Engineer