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

FORM 10-Q

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2017

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM _______ TO _______

Commission File Number 000-55615

Energy 11, L.P.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**46-3070515** (IRS Employer Identification No.)
120 W 3rd Street, Suite 220 **Fort Worth, Texas** (Address of principal executive offices)	**76102** (Zip Code)

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

As of October 31, 2017, the Partnership had 18,973,474 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Energy 11, L.P.
Consolidated Balance Sheets
(Unaudited)

	September 30, 2017	December 31, 2016
Assets		
Cash and cash equivalents	$ 44,873	$ 86,800,596
Oil, natural gas and natural gas liquids revenue receivable	5,470,375	2,718,296
Other current assets	123,750	10,038,221
Total Current Assets	5,638,998	99,557,113
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization of $21,161,505 and $9,908,800, respectively	324,040,087	151,554,972
Total Assets	$ 329,679,085	$ 251,112,085
Liabilities		
Note payable	$ 6,007,356	$ -
Accounts payable and accrued expenses	4,245,822	2,622,400
Total Current Liabilities	10,253,178	2,622,400
Asset retirement obligations	1,214,048	70,623
Total Liabilities	11,467,226	2,693,023
Partners' Equity		
Limited partners' interest (18,973,474 and 14,582,963 common units issued and outstanding, respectively)	318,213,586	248,420,789
General partners' interest	(1,727)	(1,727)
Class B Units (62,500 units issued and outstanding, respectively)	-	-
Total Partners' Equity	318,211,859	248,419,062
Total Liabilities and Partners' Equity	$ 329,679,085	$ 251,112,085

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Revenue				
Oil, natural gas and natural gas liquids revenues	$ 9,717,996	$ 5,434,047	$ 30,068,002	$ 15,285,257
Operating costs and expenses				
Production expenses	3,163,269	1,821,545	8,730,586	4,323,387
Production taxes	818,455	479,971	2,549,454	1,417,691
Management fees	-	-	-	886,306
General and administrative expenses	290,094	278,304	1,123,992	981,861
Depreciation, depletion, amortization and accretion	4,058,852	2,426,415	11,295,441	7,519,677
Total operating costs and expenses	8,330,670	5,006,235	23,699,473	15,128,922
Operating income	1,387,326	427,812	6,368,529	156,335
Interest expense, net	(106,767)	(1,938,958)	(480,495)	(6,119,320)
Net income (loss)	$ 1,280,559	$ (1,511,146)	$ 5,888,034	$ (5,962,985)
Basic and diluted net income (loss) per common unit	$ 0.07	$ (0.20)	$ 0.33	$ (0.96)
Weighted average common units outstanding - basic and diluted	18,973,474	7,686,687	17,822,804	6,210,346

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Cash flow from operating activities:		
Net income (loss)	$ 5,888,034	$ (5,962,985)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	11,295,441	7,519,677
Non-cash expenses, net	71,128	3,968,034
Changes in operating assets and liabilities:		
Oil, natural gas and natural gas liquids revenue receivable	(2,752,079)	(2,035,124)
Other current assets	(85,529)	(61,153)
Accounts payable and accrued expenses	1,178,839	475,811
Net cash flow provided by operating activities	15,595,834	3,904,260
Cash flow from investing activities:		
Cash paid for acquisition of oil and natural gas properties	(98,250,130)	-
Additions to oil and natural gas properties	(1,301,065)	(1,279,516)
Net cash flow used in investing activities	(99,551,195)	(1,279,516)
Cash flow from financing activities:		
Cash paid for deferred loan costs	-	(250,000)
Net proceeds related to issuance of units	82,510,325	104,817,830
Distributions paid to limited partners	(18,610,687)	(6,483,665)
Payments on note payable	(66,700,000)	(88,917,833)
Net cash flow provided by (used in) financing activities	(2,800,362)	9,166,332
Increase (decrease) in cash and cash equivalents	(86,755,723)	11,791,076
Cash and cash equivalents, beginning of period	86,800,596	3,287,054
Cash and cash equivalents, end of period	$ 44,873	$ 15,078,130
Interest paid	$ 433,013	$ 2,171,573
Supplemental non-cash information:		
Note payable assumed in Acquisition No. 2	40,000,000	-
Note payable assumed in Acquisition No. 3	33,000,000	-
Increase in note payable, payment of contingent consideration	-	5,000,000
Decrease in note payable, settlement of pre-close activity	292,644	1,082,167

See notes to consolidated financial statements.

Energy 11, L.P.
Notes to Consolidated Financial Statements
September 30, 2017

Note 1. Partnership Organization

Energy 11, L.P. (the "Partnership") is a Delaware limited partnership formed to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership completed its best-efforts offering on April 24, 2017 with a total of approximately 19 million common units sold for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

As of September 30, 2017, the Partnership owns an approximate 26-27% non-operated working interest in 216 existing producing wells and approximately 253 future development sites in the Sanish field located in Mountrail County, North Dakota (collectively, the "Sanish Field Assets"), which is part of the Bakken shale formation in the Greater Williston Basin. Whiting Petroleum Corporation ("Whiting"), one of the largest producers in the basin, operates substantially all of the Sanish Field Assets.

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

The Partnership's fiscal year ends on December 31.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited financial statements have been prepared in accordance with the instructions for Article 10 of SEC Regulation S-X. Accordingly, they do not include all of the information required by generally accepted accounting principles ("GAAP") in the United States. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. These unaudited financial statements should be read in conjunction with the Partnership's audited consolidated financial statements included in its 2016 Annual Report on Form 10-K. Operating results for the three and nine months ended September 30, 2017 are not necessarily indicative of the results that may be expected for the twelve-month period ending December 31, 2017.

Use of Estimates

The preparation of financial statements in conformity with United States GAAP requires management to make estimates and assumptions that affect the reported amounts in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Reclassifications

Certain prior period amounts in the consolidated financial statements have been reclassified to conform to the current period presentation with no effect on previously reported net income, partners' equity or cash flows.

Net Income (Loss) Per Common Unit

Basic net income (loss) per common unit is computed as net income (loss) divided by the weighted average number of common units outstanding during the period. Diluted net income (loss) per common unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no common units with a dilutive effect for the three and nine months ended September 30, 2017 and 2016. As a result, basic and diluted outstanding common units were the same. The Class B units and Incentive Distribution Rights, as defined below, are not included in net income (loss) per common unit until such time that it is probable Payout (as discussed in Note 6) would occur.

Recently Adopted Accounting Standards

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

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, that amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. Throughout 2016, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12 and 2016-20, respectively, to clarify specific topics originally described in ASU 2014-09. In August 2015, the FASB issued ASU No. 2015-14, which deferred the effective date of ASU 2014-09 to annual and interim periods beginning after December 15, 2017, and permitted early application for annual reporting periods beginning after December 15, 2016. The Partnership plans to adopt this standard on January 1, 2018 using the modified retrospective approach. Although the Partnership is still evaluating the impact of ASU 2014-09 and the related subsequent pronouncements released, based on its assessment to date, the Partnership does not believe there will be a significant change to the amount or timing of the recording of revenue in its consolidated financial statements.

Note 3. Oil and Natural Gas Investments

On December 18, 2015, the Partnership completed its purchase ("Acquisition No. 1") of an approximate 11% non-operated working interest in the Sanish Field Assets for approximately $159.6 million. The Partnership accounted for Acquisition No. 1 as a business combination, and therefore expensed, as incurred, transaction costs associated with this acquisition. These costs included, but were not limited to, due diligence, reserve reports, legal and engineering services and site visits.

On January 11, 2017, the Partnership completed its purchase ("Acquisition No. 2") of an additional approximate 11% non-operated working interest in the Sanish Field Assets for approximately $128.5 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 2 with the delivery of a promissory note in favor of the sellers of $40.0 million, which was paid in full in February 2017. The Partnership accounted for Acquisition No. 2 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the nine months ended September 30, 2017 were approximately $43,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.8 million in conjunction with this acquisition. Acquisition No. 2 increased the Partnership's non-operated working interest in the Sanish Field Assets to approximately 22-23%.

On March 31, 2017, the Partnership completed its purchase ("Acquisition No. 3") of an additional approximate average 10.5% non-operated working interest in 82 of the Partnership's 216 existing producing wells and 150 of the Partnership's 253 future development locations in the Sanish Field Assets ("Additional Interest") for approximately $52.4 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 3 with a promissory note in favor of the sellers of $33.0 million, discussed further in Note 4. Notes Payable. The Partnership accounted for Acquisition No. 3 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the nine months ended September 30, 2017 were approximately $80,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.3 million in conjunction with this acquisition. Acquisition No. 3 increased the Partnership's total non-operated working interest in the Sanish Field Assets to approximately 26-27%.

The following unaudited pro forma financial information for the three- and nine-month periods ended September 30, 2017 and 2016 have been prepared as if Acquisitions No. 2 and No. 3 of the Sanish Field Assets had occurred on January 1, 2016. The unaudited pro forma financial information was derived from the historical Statements 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 acquisitions of the Sanish Field Assets and related financings occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Revenues	$ 9,717,996	$ 12,704,063	$ 32,413,448	$ 35,684,151
Net income (loss)	1,517,198	(753,892)	6,210,488	(2,168,066)

Note 4. Notes Payable

As part of the financing for Acquisition No. 2 completed on January 11, 2017, the Partnership executed a note in favor of the sellers in the original principal amount of $40.0 million. The Partnership paid the $40.0 million promissory note, which bore interest at 5%, in full on February 23, 2017.

As part of the financing for Acquisition No. 3 completed on March 31, 2017, the Partnership executed a note ("Seller Note") in favor of the sellers in the original principal amount of $33.0 million. The Seller Note bore interest at 5% per annum and was payable in full no later than August 1, 2017 ("Maturity Date").

In July 2017, the Partnership and the sellers executed a First Amendment to the Seller Note ("Amended Note"), which extended the maturity date to June 29, 2018 ("Extended Maturity Date") provided the Partnership meets certain terms and conditions of the Amended Note, including making a $2.0 million payment on the outstanding principal balance by July 31, 2017. The $2.0 million payment was made by the Partnership on July 31, 2017. The Amended Note continues to bear interest at 5% per annum with interest due on the last business day of each month until the Extended Maturity Date. In addition to the $2.0 million payment and interest payments on the outstanding principal balance of the Seller Note, the Partnership is required to make principal payments of $100,000 on the last business day of each remaining month in 2017 (August through December), and principal payments of the lesser of $1,000,000 or the remaining balance on the last business day of each month in 2018 up to the Extended Maturity Date (January through June). There is no penalty for prepayment of the Amended Note. Payment of the Amended Note continues to be secured by a mortgage and liens on the Additional Interest in the Sanish Field Assets in customary form. If the Partnership sells any of its owned property, the Partnership is required to make a principal payment equal to 100% of the net proceeds of such sale until the principal amount of the Seller Note is paid in full.

As of September 30, 2017, the outstanding balance on the note of $6.0 million approximates its fair market value. The carrying value of all of the other financial instruments of the Partnership approximate fair value due to their short-term nature. The Partnership estimated the fair value of its note payable by discounting the future cash flows of each instrument at estimated market rates consistent with the maturity of a debt obligation with similar credit terms and credit characteristics, which are Level 3 inputs under the fair value hierarchy. The market rate, which approximated the Partnership's interest rate for the Seller Note, takes into consideration general market conditions and maturity.

Note 5. Asset Retirement Obligations

The Partnership records an asset retirement obligation ("ARO") and capitalizes the asset retirement costs in oil and natural gas properties in the period in which the asset 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 changes in the aggregate ARO are as follows:

	2017	2016
Balance as of January 1	$ 70,623	$ 105,459
Liabilities incurred - Acquisition No. 2	781,628	-
Liabilities incurred - Acquisition No. 3	289,827	-
Well additions	-	1,868
Revisions	28,866	(46,380)
Accretion expense	43,104	7,540
Balance as of September 30	$ 1,214,048	$ 68,487

Note 6. Capital Contribution and Partners' Equity

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

The Partnership completed its best-efforts offering of common units on April 24, 2017. As of the conclusion of the offering on April 24, 2017, the Partnership had completed the sale of approximately 19.0 million common units for total gross proceeds of $374.2 million and proceeds net of offerings costs of $349.6 million.

Under the agreement with the Dealer Manager, the Dealer Manager received a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership. Based on the common units sold through the best-efforts offering, the total contingent fee is a maximum of approximately $15.0 million.

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

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

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

First, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest (currently 43.125%).

For the three and nine months ended September 30, 2017, the Partnership paid distributions of $0.349041 and $1.047123 per common unit, or $6.6 million and $18.6 million, respectively. For the three and nine months ended September 30, 2016, the Partnership paid distributions of $0.375891 and $1.050959 per common unit, or $2.8 million and $6.5 million, respectively.

Note 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 oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to any existing related party transactions, as well as any new significant related party transactions.

On July 1, 2016, the Partnership entered into a one-year lease agreement with an affiliate of the General Partner for office space in Oklahoma City, Oklahoma. Under the terms of the agreement, the Partnership made twelve monthly payments of $8,537. The terms of the agreement will continue on a month-to-month basis at the same monthly rate for the remainder of 2017. For the three and nine months ended September 30, 2017, the Partnership paid $25,611 and $76,833 to the affiliate of the General Partner. For the three and nine months ended September 30, 2016, the Partnership paid $25,611 to the affiliate of the General Partner.

For the three and nine months ended September 30, 2017, approximately $72,000 and $242,000 of general and administrative costs were incurred by a member of the General Partner and have been or will be reimbursed by the Partnership. At September 30, 2017, approximately $72,000 was due to a member of the General Partner. For the three and nine months ended September 30, 2016, approximately $70,000 and $187,000 of general and administrative costs were incurred by a member of the General Partner and have been reimbursed by the Partnership.

The members of the General Partner are affiliates of Glade M. Knight, Chairman and Chief Executive Officer, David S. McKenney, Chief Financial Officer, Anthony F. Keating, III, Co-Chief Operating Officer and Michael J. Mallick, Co-Chief Operating Officer. Mr. Knight and Mr. McKenney are also affiliated with Energy Resources 12, L.P. Energy Resources 12, L.P. is not affiliated with the Partnership other than through Mr. Knight and Mr. McKenney. Mr. Mallick and Mr. Keating have no relationship with Energy Resources 12, L.P. The Partnership's accounting and administrative functions are shared by both partnerships and the associated costs are allocated between the entities for cost sharing purposes. The Partnership's remaining resources provide no services to Energy Resources 12, L.P. Accordingly, the Partnership disclaims any and all matters or activities in any manner related to Energy Resources 12, L.P.

E11 Incentive Holdings, LLC ("Incentive Holdings") was the owner of all Class B units outstanding (62,500) as of March 31, 2017. During the second quarter of 2017, Incentive Holdings transferred substantially all of its assets; on April 5, 2017, Incentive Holdings transferred 18,125 of the 62,500 Class B units to E11 Incentive Carry Vehicle, LLC, an affiliate of Incentive Holdings, for de minimis consideration. On April 6, 2017, the remaining 44,375 Class B units were acquired by Regional Energy Incentives, LP in exchange for approximately $98,000. Regional Energy Incentives, LP is owned by entities that are controlled by Anthony F. Keating, III, Co-Chief Operating Officer of the General Partner, Michael J. Mallick, Co-Chief Operating Officer of the General Partner, and David S. McKenney, Chief Financial Officer of the General Partner. The Class B units entitle the holder to certain distribution rights after Payout, as described in Note 6. Capital Contribution and Partners' Equity.

Note 8. Subsequent Events

In October 2017, the Partnership declared and paid $2.0 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In October 2017, an affiliate of the General Partner provided approximately $0.4 million in short-term working capital to the Partnership. The Partnership repaid the $0.4 million to the affiliate of the General Partner in November 2017.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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:

- references to future success in the Partnership's drilling and marketing activities;
- 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 the Partnership's 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 the Partnership's 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 the Partnership's strategy of acquiring oil and gas properties on attractive terms and developing those properties may not be successful or that the Partnership's operations on properties acquired may not be successful;
- general economic, market, or business conditions;
- changes in laws or regulations;
- the risk that the wells in which the Partnership acquires an interest are productive, but do not produce enough revenue to return the investment made;
- the risk that the wells the Partnership drills 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 the Partnership's ability to obtain long-term financing or refinancing debt for the Partnership's drilling activities in a timely manner and on terms that are consistent with what the Partnership projects;
- 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 the Partnership employs to reduce the effects of changes in the prices of the Partnership's production will not be effective.

Although the Partnership believes the expectations reflected in such forward-looking statements are based upon reasonable assumptions, the Partnership cannot assure investors that its 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, the Partnership undertakes 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.

The following discussion and analysis should be read in conjunction with the Partnership's Unaudited Consolidated Financial Statements and Notes thereto, appearing elsewhere in this Quarterly Report on Form 10-Q, as well as the information contained in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2016.

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 began offering common units of limited partner interest (the "common units") on a best-efforts basis on January 22, 2015, the date the Partnership's initial Registration Statement on Form S-1 (File No. 333-197476) was declared effective by the SEC. The Partnership completed its best-efforts offering on April 24, 2017. Total common units sold were approximately 19.0 million for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

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

The Partnership was formed to acquire and develop oil and gas properties located onshore in the United States. On December 18, 2015, the Partnership completed its first purchase ("Acquisition No. 1") in the Sanish field location in Mountrail County, North Dakota, acquiring an approximate 11% non-operated working interest in approximately 215 existing producing wells and approximately 253 future development locations (the "Sanish Field Assets") for approximately $159.6 million. On January 11, 2017, the Partnership closed on its second purchase ("Acquisition No. 2") in the Sanish field, acquiring an additional approximate 11% non-operated working interest in the Sanish Field Assets for approximately $128.5 million. On March 31, 2017, the Partnership closed on its third purchase ("Acquisition No. 3") in the Sanish field, acquiring an additional approximate average 10.5% non-operated working interest in 82 of the Partnership's 216 existing producing wells and 150 of the Partnership's 253 future development locations ("Additional Interest") in the Sanish Field Assets for approximately $52.4 million.

As a result of these acquisitions, as of September 30, 2017, the Partnership has an approximate 26-27% non-operated working interest in the Sanish Field Assets, consisting of 216 existing producing wells and 253 future development locations. Substantially all of the Partnership's assets are managed and operated by Whiting Petroleum Corporation ("Whiting"), a publicly traded oil and gas company.

The Sanish Field Assets are a part of the Bakken shale formation in the Greater Williston Basin. The Bakken Shale is one of the largest oil fields in the U.S.

Current Price Environment

Oil, natural gas and natural gas liquids ("NGL") prices are determined by many factors outside of the Partnership's control. Historically, energy commodity prices have been volatile; oil prices declined throughout 2015 and in the first quarter of 2016, prices had fallen to the lowest levels since October 2003. Commodity prices increased to 52-week highs by February 2017, but have since been volatile throughout the second and third quarters of 2017. Due to global supply and demand concerns as well as ongoing geopolitical risks in oil producing regions of the world, the Partnership continues to expect significant price volatility for the remainder of 2017 and into 2018. In addition to commodity price fluctuations, the Partnership faces the challenge of natural production volume declines. As reservoirs are depleted, oil and natural gas production from Partnership wells will decrease.

The following table lists average NYMEX prices for oil and natural gas for the three and nine months ended September 30, 2017 and 2016.

	Three months ended September 30,		Nine months ended September 30,	
	2017	**2016**	**2017**	**2016**
Average market closing prices [(1)]				
Oil (per Bbl)	$ 48.20	$ 44.94	$ 49.36	$ 41.49
Natural gas (per Mcf)	$ 2.95	$ 2.88	$ 3.01	$ 2.34

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

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

Results of Operations

In evaluating financial condition and operating performance, the most important indicators on which the Partnership focuses are (1) total quarterly production in barrel of oil equivalent ("BOE") units, (2) average sales price per unit for oil, natural gas and natural gas liquids, (3) production costs per BOE and (4) capital expenditures.

The following is a summary of the results from operations, including production, of the Partnership's non-operated working interest for the three and nine months ended September 30, 2017 and 2016. The results for the three and nine months ended September 30, 2017 and 2016 include results from each of the Partnership's acquisitions for the periods owned. Since the three and nine months ended September 30, 2016 includes only Acquisition No. 1, the operating results are not comparable.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017	Percent of Revenue	2016	Percent of Revenue	2017	Percent of Revenue	2016	Percent of Revenue
Total revenue	$ 9,717,996	100%	$ 5,434,047	100%	$ 30,068,002	100%	$ 15,285,257	100%
Production expenses	3,163,269	33%	1,821,545	34%	8,730,586	29%	4,323,387	28%
Production taxes	818,455	8%	479,971	9%	2,549,454	8%	1,417,691	9%
Depreciation, depletion, amortization and accretion	4,058,852	42%	2,426,415	45%	11,295,441	38%	7,519,677	49%
Management fees	-	0%	-	0%	-	0%	886,306	6%
General and administrative expense	290,094	3%	278,304	5%	1,123,992	4%	981,861	6%
Production (BOE):								
Oil	198,298		119,469		581,762		394,628	
Natural gas	40,050		26,136		114,729		68,395	
Natural gas liquids	46,326		17,667		116,477		51,890	
Total	284,674		163,272		812,968		514,913	
Average sales price per unit:								
Oil (per Bbl)	$ 40.57		$ 39.09		$ 43.02		$ 34.88	
Natural gas (per Mcf)	2.92		2.72		3.21		2.20	
Natural gas liquids (per Bbl)	20.98		13.03		24.27		11.86	
Combined (per BOE)	34.14		33.28		36.99		29.69	
Average unit cost per BOE:								
Production expenses	$ 11.11		$ 11.16		$ 10.74		$ 8.40	
Production taxes	2.88		2.94		3.14		2.75	
Depreciation, depletion, amortization and accretion	14.26		14.86		13.89		14.60	

Oil, Natural Gas and NGL Sales

For the three months ended September 30, 2017, revenues for oil, natural gas and NGL sales were $9.7 million. Revenues for the sale of crude oil were $8.0 million, which resulted in a realized price of $40.57 per barrel. Revenues for the sale of natural gas were $0.7 million, which resulted in a realized price of $2.92 per Mcf. Revenues for the sale of NGLs were $1.0 million, which resulted in a realized price of $20.98 per BOE of production. For the three months ended September 30, 2016, revenues for oil, natural gas and NGL sales were $5.4 million. Revenues for the sale of crude oil were $4.7 million, which resulted in a realized price of $39.09 per barrel. Revenues for the sale of natural gas were $0.4 million, which resulted in a realized price of $2.72 per MCF. Revenues for the sale of NGLs were $0.3 million, which resulted in a realized price of $13.03 per BOE of production.

For the nine months ended September 30, 2017, revenues for oil, natural gas and NGL sales were $30.1 million. Revenues for the sale of crude oil were $25.0 million, which resulted in a realized price of $43.02 per barrel. Revenues for the sale of natural gas were $2.2 million, which resulted in a realized price of $3.21 per Mcf. Revenues for the sale of NGLs were $2.8 million, which resulted in a realized price of $24.27 per BOE of production. For the nine months ended September 30, 2016, revenues for oil, natural gas and NGL sales were $15.3 million. Revenues for the sale of crude oil were $13.8 million, which resulted in a realized price of $34.88 per barrel. Revenues for the sale of natural gas were $0.9 million, which resulted in a realized price of $2.20 per MCF. Revenues for the sale of NGLs were $0.6 million, which resulted in a realized price of $11.86 per BOE of production.

In comparison to the third quarter and first nine months of 2016, the Partnership benefited from increases in commodity prices for oil, natural gas and NGLs during the first nine months of 2017, as market prices rebounded from market lows experienced during the first quarter of 2016. Price gains were partially offset by the natural decline in production from existing wells, as the Partnership did not start or complete any new wells during the nine months ended September 30, 2017. Production for the interest acquired in Acquisition No. 1, which was owned for the entire periods presented, was approximately 1,331 BOE per day and approximately 1,775 BOE per day for the three months ended September 30, 2017 and 2016, respectively. Production for the interest acquired in Acquisition No. 1 was approximately 1,360 BOE per day and approximately 1,879 BOE per day for the nine months ended September 30, 2017 and 2016, respectively.

Production is dependent on the investment in existing wells and the development of new wells. Although the Partnership has elected to participate in the drilling of two new wells, the Partnership does not anticipate to realize any increases to overall production from these two wells until the first quarter of 2018, and as a result, production is anticipated to decline in the fourth quarter of 2017. If the Partnership or its operator is unable or it is not cost beneficial to invest in existing wells or develop new wells, production will continue to decline.

Operating Costs and Expenses

Production Expenses

Production expenses are daily costs incurred by the Partnership to bring oil and natural gas out of the ground and to market, along with the daily costs incurred to maintain producing properties. Such costs include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to the Partnership’s oil and natural gas properties.

For the three months ended September 30, 2017 and 2016, production expenses were $3.2 million and $1.8 million, respectively, and production expenses per BOE of production were $11.11 and $11.16, respectively. For the nine months ended September 30, 2017 and 2016, production expenses were $8.7 million and $4.3 million, respectively, and production expenses per BOE of production were $10.74 and $8.40, respectively. The increase per BOE in the nine-month period ended September 30, 2017 compared to the nine-month period ended September 30, 2016 is due primarily to the following factors: (a) in an effort to increase production, a portion of the Partnership’s wells required substantial rework, resulting in an increase in workover expenses in 2017; (b) during the third quarter of 2016, the Partnership’s operator amended its gathering and processing contract, which has led to increases in certain gathering and processing costs subsequent to the amendment date; and (c) higher third-party fractionation expenses and plant processing costs in 2017. While production expenses per BOE of production have stabilized, the Partnership expects production expenses per BOE of production to increase due to natural production volume declines as reservoirs are depleted.

Production Taxes

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

The production tax on gas is subject to a price index change on July 1 of each calendar year. The rate applicable for the first half of 2017 was $0.0601 per Mcf, while the rate effective for the first half of 2016 was $0.1106 per Mcf. The new rate, which became effective July 1, 2017 and will run through June 30, 2018, is $0.0555 per Mcf.

Production taxes for the three months ended September 30, 2017 and 2016 were $0.8 million (8% of revenue) and $0.5 million (9% of revenue), respectively. Production taxes for the nine months ended September 30, 2017 and 2016 were $2.5 million (8% of revenue) and $1.4 million (9% of revenue), respectively. Production taxes as a percentage of revenue have decreased as sales of natural gas and NGL have increased as a percentage of total sales. Taxes on the sale of gas and NGL products are less than taxes levied on the sale of oil based on current rates as a percentage of sale price.

Depreciation, Depletion, Amortization and Accretion (“DD&A”)

DD&A of capitalized drilling and development costs of producing oil, natural gas and NGL properties are computed using the unit-of-production method on a field basis based on total estimated proved developed oil, natural gas and NGL reserves. Costs of acquiring proved properties are depleted using the unit-of-production method on a field basis based on total estimated proved developed and undeveloped reserves. DD&A for the three months ended September 30, 2017 and 2016 was $4.1 million and $2.4 million, and DD&A per BOE of production was $14.26 and $14.86, respectively. DD&A for the nine months ended September 30, 2017 and 2016 was $11.3 million and $7.5 million, and DD&A per BOE of production was $13.89 and $14.60, respectively. The decrease in DD&A expense per BOE of production is primarily the result of the increase of the Partnership’s estimated reserves compared to the purchase price in conjunction with Acquisitions No. 2 and No. 3, combined with a change in estimated reserves.

Management Fees

Fees and expenses incurred under the Management Agreement with the Partnership's former manager for the nine months ended September 30, 2016 were $0.9 million. The Management Agreement was terminated in April 2016.

General and Administrative Costs

General and administrative costs for the three months ended September 30, 2017 and 2016 were $0.3 million and $0.3 million, respectively. General and administrative costs for the nine months ended September 30, 2017 and 2016 were $1.1 million and $1.0 million, respectively. The principal components of general and administrative expense are accounting, legal and consulting fees.

Interest Expense

Interest expense, net, for the three months ended September 30, 2017 and 2016 was $0.1 million and $1.9 million, respectively. Interest expense, net, for the nine months ended September 30, 2017 and 2016 was $0.5 million and $6.1 million, respectively. The primary component of Interest Expense, net, during the three and nine months ended September 30, 2017 was interest expense on the notes payable executed in conjunction with Acquisitions No. 2 and No. 3.

During the first three quarters of 2016, Interest expense, net, included (a) nine months of interest expense on the $97.5 million seller note related to Acquisition No. 1 (the note was paid in full in September 2016), (b) nine months of amortization of the mark-to-market adjustment on the $97.5 million seller note; and (c) accretion of the Partnership's deferred purchase price and contingent consideration liabilities incurred with Acquisition No. 1.

Supplemental Non-GAAP Measure

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

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

The following table reconciles the Partnership's GAAP net income (loss) to EBITDAX for the three and nine months ended September 30, 2017 and 2016.

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Net income (loss)	$ 1,280,559	$ (1,511,146)	$ 5,888,034	$ (5,962,985)
Interest expense, net	106,767	1,938,958	480,495	6,119,320
Depreciation, depletion, amortization and accretion	4,058,852	2,426,415	11,295,441	7,519,677
Exploration expenses	-	-	-	-
EBITDAX	$ 5,446,178	$ 2,854,227	$ 17,663,970	$ 7,676,012

Liquidity and Capital Resources

With the completion of the Partnership's best-efforts offering in April 2017, the Partnership's principal source of liquidity are cash on hand and the cash flow generated from properties the Partnership has acquired. The Partnership anticipates that cash on hand and cash flow from operations will be adequate to meet its anticipated liquidity requirements. In addition, the Partnership may borrow funds to pay operating expenses, make distributions, refinance outstanding debt or for other capital needs of the Partnership. The Partnership is pursuing a credit facility to provide additional liquidity for capital needs and other corporate working capital requirements. However, there can be no assurance the Partnership will enter into a credit facility.

Financing

As part of the financing for Acquisition No. 2 on January 11, 2017, the Partnership executed a note in favor of the sellers in the original principal amount of $40.0 million. The Partnership paid the $40.0 million promissory note, which bore interest at 5%, in full on February 23, 2017.

As part of the financing for Acquisition No. 3, the Partnership executed a promissory note in favor of the sellers in the original principal amount of $33.0 million. During July 2017, the Partnership and the sellers executed a first amendment to the note ("Amended Note"), which extended the maturity date to June 29, 2018 ("Extended Maturity Date") provided the Partnership meets certain terms and conditions of the Amended Note, including making a $2.0 million payment on the outstanding principal balance. The $2.0 million payment was made by the Partnership on July 31, 2017. The Amended Note continues to bear interest at 5% per annum with interest due on the last business day of each month until the Extended Maturity Date. In addition to the $2.0 million payment and interest payments on the outstanding principal balance of the Seller Note, the Partnership is required to make principal payments of $100,000 on the last business day of each remaining month in 2017 (August through December), and principal payments of the lesser of $1,000,000 or the remaining balance on the last business day of each month in 2018 up to the Extended Maturity Date (January through June). There is no penalty for prepayment of the Amended Note. Payment of the Amended Note continues to be secured by a mortgage and liens on the Additional Interest in the Sanish Field Assets in customary form. If the Partnership sells any of its owned property, the Partnership is required to make a principal payment equal to 100% of the net proceeds of such sale until the principal amount of the Seller Note is paid in full.

At September 30, 2017, the outstanding balance on the note was $6.0 million.

The Partnership anticipates refinancing the Amended Note or using cash on hand and cash flow from operations to repay the remaining note balance. If the Partnership cannot repay the note, it may be in default and be required to reduce distributions.

Partners Equity

The Partnership completed its best-efforts offering of common units on April 24, 2017. As of the conclusion of the offering on April 24, 2017, the Partnership sold approximately 19.0 million common units for total gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

Under the agreement with the Dealer Manager, the Dealer Manager received a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership. Based on the common units sold in the offering, the total contingent fee is a maximum of approximately $15.0 million, which will only be paid if Payout occurs, as defined in "Note 6. Capital Contribution and Partners' Equity" in Part I, Item 1 of this Form 10-Q.

Distributions

For the three and nine months ended September 30, 2017, the Partnership paid distributions of $0.349041 and $1.047123 per common unit, or $6.6 million and $18.6 million, respectively. For the three and nine months ended September 30, 2016, the Partnership paid distributions of $0.375891 and $1.050959 per common unit, or $2.8 million and $6.5 million, respectively. The Partnership generated $15.6 million in cash flow from operations for the nine months ended September 30, 2017.

Since a portion of distributions to date have been funded with proceeds from the offering of common units, the Partnership's ability to maintain its current rate of distribution ($1.40 per unit per year) will be based on its ability to increase its cash generated from operations. As there can be no assurance that the Partnership's current assets will provide income at this level, there can be no assurance as to the classification or duration of distributions at the current rate.

Oil and Natural Gas Properties

The Partnership incurred approximately $0.9 million and $1.7 million in capital expenditures for the three and nine months ended September 30, 2017, respectively. The Partnership incurred approximately $0.4 million and $1.5 million in capital expenditures for the three and nine months ended September 30, 2016, respectively.

In October 2017, the Partnership elected to participate in the drilling and completion of two new wells at an estimated total cost to the Partnership of approximately $1.4 million. It is anticipated these two new wells will be completed by December 2017. The Partnership has also received proposals for the drilling and completion of four additional wells, to be started in late 2017 and completed in the first quarter of 2018, at an estimated total cost to the Partnership of approximately $5.6 million. Currently, the Partnership plans to participate in drilling and completion of these four additional wells. Therefore, planned capital expenditures for the fourth quarter of 2017 are approximately $3.5 to $4.0 million, which includes the two new wells, a portion of the costs to drill the four additional wells and other capital costs incurred to rework certain wells to maintain production levels.

Since the Partnership is not the operator of any of its oil and natural gas properties, it is difficult to predict levels of future participation in the drilling and completion of new wells and their associated capital expenditures. This makes capital expenditures for drilling and completion projects difficult to forecast for 2018. As a result, the capital expenditure plan for 2018 has the flexibility to adjust based upon the commodity price environment, which the Partnership continues to monitor to ensure any new wells are cost beneficial. Current estimated capital expenditures could be significantly different from amounts actually invested.

The Partnership expects to fund overhead costs and capital additions related to the drilling and completion of wells primarily from cash provided by operating activities, cash on hand and a credit facility. If the operator elects to complete drilling or other significant capital expenditure activity and the Partnership is unable to fund the capital expenditures, the General Partner may decide to farmout the well. Also, if a well is proposed under the operating agreement for one of the properties the Partnership owns, the General Partner may elect to “non-consent” the well. Non-consenting a well will generally cause the Partnership not to be obligated to pay the costs of the well, but the Partnership will not be entitled to the proceeds of production from the well until a penalty is received by the parties that drilled the well.

Transactions with Related Parties

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

See further discussion in “Note 7. Related Parties” in Part I, Item 1 of this Form 10-Q.

Subsequent Events

In October 2017, the Partnership declared and paid $2.0 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In October 2017, an affiliate of the General Partner provided approximately $0.4 million in short-term working capital to the Partnership. The Partnership repaid the $0.4 million to the affiliate of the General Partner in November 2017.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a–15 and 15d–15 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), the Partnership carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer of the General Partner, of the effectiveness of the Partnership’s 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 concluded that the Partnership’s disclosure controls and procedures were effective as of September 30, 2017 to provide reasonable assurance that information required to be disclosed in the Partnership’s 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. The Partnership’s 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 management, including the Chief Executive Officer and the Chief Financial Officer of the General Partner, as appropriate, to allow timely decisions regarding required disclosure.

Change in Internal Controls Over Financial Reporting

There have not been any changes in the Partnership’s internal controls over financial reporting that occurred during the quarterly period ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, the Partnership’s internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors

For a discussion of the Partnership's potential risks and uncertainties, see the section titled "Risk Factors" in the 2016 Form 10-K. There have been no material changes to the risk factors previously disclosed in the 2016 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Not applicable.

Item 3. Defaults upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Exhibit No.	Description
2.6	Interest Purchase Agreement dated March 8, 2017 among Energy 11 Operating Company, LLC, Kaiser Acquisition and Development – Whiting, LLC, and Kaiser Acquisition and Development, LLC and George B. Kaiser. (incorporated by reference from Exhibit 2.1 to the Registrant's Form 8-K filed March 10, 2017)
10.4	Secured Promissory Note dated March 31, 2017 executed by Energy 11 Operating Company, LLC in favor of Kaiser-Francis Management Company, L.L.C. (incorporated by reference from Exhibit 10.1 to the Registrant's Form 8-K filed March 31, 2017)
10.5	First Amendment dated July 21, 2017 to Secured Promissory Note dated March 31, 2017 between Energy 11 Operating Company, LLC and Kaiser-Francis Management Company, L.L.C. (incorporated by reference from Exhibit 10.5 to the Registrant's Form 10-Q filed on August 11, 2017)
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*
101	The following materials from Energy 11, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 formatted in XBRL (eXtensible Business Reporting Language): (i) the Balance Sheets, (ii) the Statements of Operations, (iii) the Statements of Cash Flows, and (iv) related notes to these financial statements, tagged as blocks of text and in detail*

*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 G.P., LLC, its General Partner

By: /s/ Glade M. Knight
Glade M. Knight
Chief Executive Officer
(Principal Executive Officer)

By: /s/ David S. McKenney
David S. McKenney
Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: November 3, 2017

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 Quarterly Report on Form 10-Q 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: November 3, 2017	By:	/s/ Glade M. Knight
	Name:	Glade M. Knight
	Title:	General Partner, Chief Executive Officer (Principal Executive Officer)

EXHIBIT 31.2

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

I, David McKenney, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: November 3, 2017	By:	/s/ David S. McKenney
	Name:	David S. McKenney
	Title:	General Partner, Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT 32.1

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

This certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and accompanies the Quarterly Report on Form 10-Q (the "Form 10-Q") for the three months ended September 30, 2017 of Energy 11, L.P. (the "Partnership"). I, Glade M. Knight, the Chief Executive Officer of the Partnership, certify that, based on my knowledge:

(1) The Form 10-Q 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-Q fairly presents, in all material respects, the financial condition and results of operations of the Partnership as of and for the periods covered in this report.

Date: November 3, 2017

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

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 Quarterly Report on Form 10-Q (the "Form 10-Q") for the three months ended September 30, 2017 of Energy 11, L.P. (the "Partnership"). I, David McKenney, the Chief Financial Officer of the Partnership, certify that, based on my knowledge:

(1) The Form 10-Q 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-Q fairly presents, in all material respects, the financial condition and results of operations of the Partnership as of and for the periods covered in this report.

Date: November 3, 2017

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