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, 2018

☐ 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 000-55916

Energy Resources 12, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**81-4805237**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
120 W 3rd Street, Suite 220	
Fort Worth, Texas	**76102**
(Address of principal executive offices)	(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 every Interactive Data File required to be submitted 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 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 ☐	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, 2018, the Partnership had 7,078,120 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Energy Resources 12, L.P.
Consolidated Balance Sheets
(Unaudited)

	September 30, 2018	December 31, 2017
Assets		
Cash and cash equivalents	$ 5,599,013	$ 46,859,728
Oil, natural gas and natural gas liquids revenue receivable, net	3,226,980	-
Deposit for potential acquisition	-	8,750,000
Deferred acquisition costs	-	4,884,208
Total Current Assets	8,825,993	60,493,936
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization of $3,035,014 and $0, respectively	172,973,512	-
Other assets, net	1,650,485	-
Total Assets	$ 183,449,990	$ 60,493,936
Liabilities		
Term loan	$ 15,000,000	$ -
Accounts payable and accrued expenses	3,960,126	164,786
Due to related parties	492,371	5,283,623
Derivative liability	57,306	-
Total Current Liabilities	19,509,803	5,448,409
Revolving credit facility	44,500,000	-
Asset retirement obligations	349,745	-
Total Liabilities	64,359,548	5,448,409
Partners' Equity		
Limited partners' interest (6,485,774 and 3,191,231 common units issued and outstanding, respectively)	119,090,657	55,045,742
General partner's interest	(215)	(215)
Total Partners' Equity	119,090,442	55,045,527
Total Liabilities and Partners' Equity	$ 183,449,990	$ 60,493,936

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Revenue				
Oil	$ 5,062,458	$ -	$ 15,270,432	$ -
Natural gas	252,829	-	628,436	-
Natural gas liquids	188,419	-	633,013	-
Total revenue	5,503,706	-	16,531,881	-
Operating costs and expenses				
Production expenses	945,233	-	3,213,860	-
Production taxes	548,574	-	1,487,100	-
General and administrative expenses	360,382	28,226	1,104,416	49,331
Depreciation, depletion, amortization and accretion	1,024,676	-	3,040,755	-
Total operating costs and expenses	2,878,865	28,226	8,846,131	49,331
Operating income (loss)	2,624,841	(28,226)	7,685,750	(49,331)
Loss on derivatives	(57,306)	-	(57,306)	-
Interest income (expense), net	(479,810)	40,750	(851,859)	39,645
Net income (loss)	$ 2,087,725	$ 12,524	$ 6,776,585	$ (9,686)
Basic and diluted net income (loss) per common unit	$ 0.37	$ 0.01	$ 1.53	$ (0.02)
Weighted average common units outstanding - basic and diluted	5,640,746	1,409,731	4,417,011	475,074

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Cash flow from operating activities:		
Net income (loss)	$ 6,776,585	$ (9,686)
Adjustments to reconcile net income to cash from operating activities:		
Depreciation, depletion, amortization and accretion	3,040,755	-
Loss on mark-to-market of derivatives	57,306	-
Non-cash expenses	47,157	
Changes in operating assets and liabilities:		
Oil, natural gas and natural gas liquids revenue receivable	(3,957,023)	-
Due to related parties	(66,252)	-
Accounts payable and accrued expenses	935,821	8,358
Net cash flow provided by (used in) operating activities	6,834,349	(1,328)
Cash flow from investing activities:		
Cash paid for acquisition of oil and natural gas properties	(161,390,163)	-
Additions to oil and natural gas properties	(1,798,654)	-
Net cash flow used in investing activities	(163,188,817)	-
Cash flow from financing activities:		
Cash paid for loan costs	(1,697,642)	-
Proceeds from line of credit	-	229,000
Payments on line of credit	-	(229,000)
Proceeds from term loan	25,000,000	-
Payments on term loan	(10,000,000)	-
Net proceeds from revolving credit facility	44,500,000	
Proceeds from advance from member of general partner	7,000,000	-
Payments on advance from member of general partner	(7,000,000)	-
Net proceeds related to issuance of units	61,878,639	45,420,915
Distributions paid to limited partners	(4,587,244)	(477,744)
Net cash flow provided by financing activities	115,093,753	44,943,171
Increase (decrease) in cash and cash equivalents	(41,260,715)	44,941,843
Cash and cash equivalents, beginning of period	46,859,728	1,000
Cash and cash equivalents, end of period	$ 5,599,013	$ 44,942,843
Interest paid	$ 606,395	$ 1,420

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Notes to Consolidated Financial Statements
September 30, 2018
(Unaudited)

Note 1. Partnership Organization

Energy Resources 12, 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 December 30, 2016. 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 $350,000,001 of capital, consisting of 17,631,579 common units. The Partnership’s offering was declared effective by the Securities and Exchange Commission (“SEC”) on May 17, 2017. As of July 25, 2017, the Partnership completed the sale of the minimum offering of 1,315,790 common units. The subscribers to the common units were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time.

As of September 30, 2018, the Partnership owned an approximate 6.0% non-operated working interest in 243 currently producing wells and 47 wells in various stages of the drilling and completion process, predominantly in McKenzie, Dunn, McLean and Mountrail counties of North Dakota (collectively, the “Bakken Assets”). The Bakken Assets, which are a part of the Bakken shale formation in the Greater Williston Basin, are operated by 14 third-party operators on behalf of the Partnership and other working interest owners.

The general partner of the Partnership is Energy Resources 12 GP, LLC (the “General Partner”). The General Partner manages and controls the business affairs of the Partnership. David Lerner Associates, Inc. (the “Managing Dealer”), is acting as the dealer manager for the offering of the common units.

The Partnership’s fiscal year ends on December 31.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying 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 for complete financial statements. 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 December 31, 2017 financial statements included in its 2017 Annual Report on Form 10-K. Operating results for the three and nine months ended September 30, 2018 are not necessarily indicative of the results that may be expected for the twelve-month period ending December 31, 2018.

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 the Managing Dealer, 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 partners’ equity. As of September 30, 2018, the Partnership had completed the sale of 6.5 million common units for gross proceeds of approximately $127.1 million and proceeds net of offering costs of approximately $118.9 million.

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.

The Partnership does not operate its oil and natural gas properties and receives actual oil, natural gas and natural gas liquids ("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. Therefore, the Partnership has used the most current available production data gathered from its operators and the Oil and Gas Division of the North Dakota Industrial Commission, and oil, natural gas and NGL national index prices 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 or the settlement proceeds are received.

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 per common unit is computed as net income divided by the weighted average number of common units outstanding during the period. Diluted net income 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, 2018. As a result, basic and diluted outstanding common units were the same. The Incentive Distribution Rights (as discussed in Note 8) are not included in net income per common unit until such time that it is probable Payout (as discussed in Note 8) will occur.

Revenue Recognition

Since it did not acquire any assets until 2018, the Partnership did not record any revenue in 2017. The Partnership is bound by a joint operating agreement with the operator of each of its producing and in-process wells. Under the joint operating agreement, the Partnership's proportionate share of production is marketed at the discretion of the operators. Virtually all of the Partnership's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers. The Partnership typically satisfies its performance obligations upon transfer of control of its products and records the related revenue in the month production is delivered to the purchaser. Settlement receipts for sales of oil, natural gas and natural gas liquids may not be received for more than a month after the date production is delivered to the purchaser, and as a result, the Partnership is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Partnership records the differences between estimates and the actual amounts received for product sales in the month that settlement proceeds are received from the operator.

The Partnership disaggregates its revenue on the face of the consolidated statements of operations for the three and nine months ended September 30, 2018.

Recently Adopted Accounting Standards

In August 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815), Targeted Improvements to Accounting for Hedging Activities*, which amends the hedge accounting model to enable entities to better portray their risk management activities in their financial statements and enhance the transparency and understandability of hedging activity. The standard simplifies the application of hedge accounting and reduces the administrative burden of hedge documentation requirements and assessing hedge effectiveness. The standard is effective for annual and interim periods beginning after December 15, 2018 with early adoption permitted. The standard requires a modified retrospective approach for all hedge relationships that exist on the date of adoption. The presentation and disclosure guidance is required only prospectively. The Partnership adopted this standard on January 1, 2018. As of January 1, 2018, the Partnership did not have any outstanding hedge positions; therefore, the adoption of this standard did not have a material impact on the Partnership's consolidated financial statements. The Partnership entered into derivative contracts in September 2018; refer to Note 7. Risk Management for additional information.

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 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 and 2017, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 2016-20, 2017-13 and 2017-14, 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 adopted this standard on January 1, 2018. The Partnership did not recognize any revenue for any period prior to adoption of this standard.

Recently Issued Accounting Standards

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 as right-of-use assets and lease liabilities. The standard is effective for annual and interim periods beginning after December 15, 2018 with early adoption permitted. The Partnership expects to adopt this standard as of January 1, 2019. Although the Partnership has not yet identified any material impact, the Partnership is still evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

Note 3. Oil and Gas Investments

On February 1, 2018, the Partnership completed its purchase ("Acquisition No. 1") of an approximate average 3.1% non-operated working interest in the Bakken Assets for approximately $87.5 million. Acquisition No. 1 was funded using proceeds from the Partnership's best-efforts offering, proceeds from an unsecured term loan of $25.0 million (discussed below in Note 5. Debt), and an advance from a member of the General Partner, of $7.0 million. The advance from a member of the General Partner was repaid in full in May 2018. The advance did not bear interest and the member of the General Partner did not receive any compensation for the advance. At closing, the Partnership's interest in the Bakken Assets was comprised of approximately 204 existing producing wells, 30 wells in various stages of the drilling and completion process and additional future development locations.

The Partnership accounted for Acquisition No. 1 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. These acquisition-related costs included, but were not limited to, fees for advisory and consulting (discussed below), due diligence, legal, accounting, engineering and environmental review services. The Partnership capitalized approximately $5.0 million in transaction costs in conjunction with Acquisition No. 1. The Partnership also recorded an asset retirement obligation liability of approximately $0.1 million in conjunction with this acquisition. See Note 4. Asset Retirement Obligation below.

The Partnership adjusted the purchase price to reflect the operating revenues and expenses of Acquisition No. 1 between the acquisition effective date of September 1, 2017 and the closing date of February 1, 2018, in accordance with the closing conditions set forth in the purchase agreement. The net impact of the purchase price adjustments was a decrease to the purchase price of the asset of approximately $2.1 million.

Since closing on Acquisition No. 1 on February 1, 2018, the Partnership participated in the drilling of 78 wells, of which 38 have been completed and 40 wells were in various stages of completion at August 30, 2018. As of August 30, 2018, the Partnership owned an approximate 3.1% non-operated working interest in 242 currently producing wells, 40 wells in various stages of the drilling and completion process, and additional future development locations in the Bakken Assets.

On August 31, 2018, the Partnership completed its purchase (“Acquisition No. 2”) of an additional non-operated working interest in the Bakken Assets for approximately $82.5 million, subject to customary adjustments, and was funded using proceeds from the Partnership’s best-efforts offering and proceeds from a line of credit of $60.0 million (discussed below in Note 5. Debt). 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. The capitalized acquisition-related costs, which included but were not limited to those listed above, for Acquisition No. 2 totaled approximately $2.9 million.

During the third quarter of 2018, the Partnership adjusted the purchase price of Acquisition No. 2 to reflect the Partnership’s estimate of the customary settlement of operating revenues and expenses received or paid by the seller on the Partnership’s behalf between the effective date of March 1, 2018 and the closing date of August 31, 2018. The estimate, which is preliminary and was derived from operator revenue and expense statements received from the seller, reduced the purchase price of the Bakken Assets by approximately $5.7 million. In accordance with the terms of the purchase agreement, the Partnership and the seller will agree to the final settlement of operating revenues and expenses between the effective and closing dates of the acquisition after all operator information has been received, and the Partnership will adjust its estimate at that time.

In November 2017, the Partnership engaged Regional Energy Investors, LP (“REI”) to perform advisory and consulting services, including supporting the Partnership through closing and post-closing of Acquisition No. 1. In the first quarter of 2018, the Partnership paid REI a total of approximately $5.3 million for its advisory and consulting services related to Acquisition No. 1. Of the $5.3 million paid to REI, approximately $4.7 million of these services related to Acquisition No. 1 were capitalized as part of the acquisition costs described above. In June 2018, the Partnership re-engaged REI to perform advisory and consulting services and support the Partnership through closing and post-closing of Acquisition No. 2, including assistance with due diligence and obtaining financing for Acquisition No. 2. In the third quarter of 2018, the Partnership paid REI a total of $4.1 million for its advisory and consulting services related to Acquisition No. 2. Of the $4.1 million, approximately $2.7 million of these services related to Acquisition No. 2 were capitalized as part of the acquisition costs described above. The remaining $1.4 million was capitalized as deferred loan costs and will be amortized over the life of the revolving credit facility described in Note 5. Debt. The deferred loan costs are recorded as Other assets, net on the Partnership’s consolidated balance sheet. REI is also entitled to a fee of 5% of the gross sales price in the event the Partnership disposes any or all of the Bakken Assets, if surplus funds are available after Payout to the holders of the Partnership’s common units, as defined in Note 8 below.

REI is owned by entities that are controlled by Anthony F. Keating, III, Co-Chief Operating Officer of Energy 11 GP, LLC, and Michael J. Mallick, Co-Chief Operating Officer of Energy 11 GP, LLC. Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of Energy 11 GP, LLC as well as the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner. See Note 9. Related Parties below for additional information.

The following unaudited pro forma financial information for the three and nine months ended September 30, 2018 and 2017 have been prepared as if Acquisitions No.1 and No. 2 of the Bakken Assets had occurred on January 1, 2017. The unaudited pro forma financial information was derived from the historical statements of operations of the Partnership and the historical financial statements of the sellers of the Bakken Assets. 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 Bakken 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, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Revenues	$ 8,502,204	$ 8,662,277	$ 33,834,094	$ 21,124,520
Net income	4,482,246	3,819,872	15,388,742	7,715,023

As of September 30, 2018, the Partnership’s ownership of the Bakken Assets consisted of an approximate 6.0% non-operated working interest in 243 currently producing wells and 47 wells in various stages of the drilling and completion process. Since completing Acquisition No. 1 through September 30, 2018, the Partnership incurred approximately $5.6 million in capital drilling and completion costs. During this period, the Partnership participated in the drilling of 86 wells, of which 39 have been completed and 47 wells are in various stages of completion at September 30, 2018. The Partnership anticipates approximately $22 million remain to complete the 47 wells in various stages of completion.

Note 4. 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:

		2018
Balance as of January 1, 2018	$	-
Liabilities incurred on February 1, 2018 (Acquisition No. 1)		133,155
Liabilities incurred on August 31, 2018 (Acquisition No. 2)		170,823
Well additions		40,025
Accretion		5,742
Balance as of September 30, 2018	$	349,745

Note 5. Debt

On January 16, 2018, the Partnership entered into a loan agreement with Bank of America, N.A. ("BOA"), as the lender, for an unsecured term loan ("Term Loan") of $25.0 million. The Term Loan bears interest at a variable rate based on the London Inter-Bank Offered Rate (LIBOR) plus a margin of 2.00%. Interest is payable monthly.

The Partnership used the $25.0 million proceeds from the Term Loan to fund Acquisition No. 1, as described in Note 3. Oil and Gas Investments above. Under the terms of the loan agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. However, as discussed below, prepayments are limited under the terms of the Credit Facility. The Term Loan contains mandatory prepayment requirements, customary affirmative and negative covenants and events of default. Messrs. Knight and McKenney have guaranteed repayment of the Term Loan and have not and will not receive any consideration in exchange for providing this guarantee.

On August 31, 2018, the Partnership entered into a loan agreement ("Loan Agreement") with Simmons Bank as administrative agent and the lenders party thereto (collectively, the "Lender"), which provides for a revolving credit facility (the "Credit Facility") with an initial commitment amount of $60 million (the "Revolver Commitment Amount"), subject to borrowing base restrictions. The commitment amount may be increased up to $100 million with Lender approval. At closing, the Partnership paid an origination fee of 0.50% of the Revolver Commitment Amount, or $300,000, and is subject to additional origination fees of 0.50% for any increase to the commitment made in excess of the Revolver Commitment Amount. The Partnership is also required to pay an unused facility fee at an annual rate of 0.50% on the unused portion of the Revolver Commitment Amount, based on the amount of borrowings outstanding during a quarter. The maturity date is August 31, 2021 ("Maturity Date").

Under the Loan Agreement, the initial borrowing base is $60 million. However, the borrowing base is subject to redetermination semi-annually based upon the Lender's analysis of the Partnership's proven oil and natural gas reserves. In addition, the Partnership's monthly mandatory principal payments (discussed below) reduce the Partnership's borrowing base; the borrowing base minimum is $40 million. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time. The interest rate, subject to certain exceptions, is equal to the London Inter-Bank Offered Rate (LIBOR) plus a margin ranging from 2.75% to 3.75%, depending upon the Partnership's borrowing base utilization, as calculated under the terms of the Loan Agreement. In addition to monthly interest payments on the outstanding principal balance of the note, the Partnership (subject to certain exceptions) must make mandatory principal payments monthly in an amount equal to 100% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the note is reduced to $40 million. The Partnership is required to reduce the outstanding principal amount of the note to at or below $40 million by March 15, 2019.

The Loan Agreement also requires the Partnership to maintain a risk management program to manage the commodity price risk on the Partnership's future oil and natural gas production. The program must cover at least 80% of the Partnership's total monthly production of oil and natural gas through March 31, 2019, and from April 1, 2019 to the Maturity Date, the program must cover at least 50% of the Partnership's total monthly oil and natural gas production. See additional detail in Note 7. Risk Management.

At closing, the Partnership borrowed $60.0 million. The proceeds were used to fund the purchase of Acquisition No. 2 described above and to pay closing costs. Subject to availability, the Credit Facility may also provide additional liquidity for future capital investments, including the drilling and completion of proposed wells by the operators of the Partnership's properties, and other corporate working capital requirements. Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. The Credit Facility is secured by a mortgage and first lien position on at least 90% of the Partnership's producing wells.

The Credit Facility contains mandatory prepayment requirements (including those described above), customary affirmative and negative covenants and events of default. The financial covenants as defined in the Loan Agreement include:

- a maximum leverage ratio
- a minimum current ratio
- maximum distributions

The Partnership was in compliance with the applicable covenants at September 30, 2018.

As a condition to closing on the Credit Facility, the Partnership was required to extend the maturity of Term Loan with BOA to April 15, 2019 from its original maturity date of January 15, 2019. Also, BOA was required to consent to the Partnership entering into the Credit Facility. The Partnership and BOA amended the Term Loan on August 16, 2018, whereby BOA gave consent and extended the maturity date. Under the Credit Facility, no principal payments can be made on the BOA loan until the outstanding balance on the Credit Facility is less than $40.0 million.

As of September 30, 2018, the outstanding balance and the applicable interest rate on the Term Loan were $15.0 million and 4.25%, respectively. As of September 30, 2018, the outstanding balance and the applicable interest rate on the Credit Facility were $44.5 million and 5.71%, respectively. The outstanding balances at September 30, 2018 approximate the fair market value of the Term Loan and Credit Facility. The Partnership estimated the fair values of its Term Loan and Credit Facility by discounting the future cash flows of the instrument at estimated market rates consistent with the maturity of a debt obligation with similar credit terms and credit characteristics, which are Level 3 inputs under the fair value hierarchy. Market rates take into consideration general market conditions and maturity.

Note 6. Fair Value of Financial Instruments

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

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

The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and the consideration of factors specific to the asset or liability. The Partnership's policy is to recognize transfers in or out of a fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Partnership has consistently applied the valuation techniques discussed above for all periods presented. During the three and nine months ended September 30, 2018 and 2017, there were no transfers in or out of Level 1, Level 2, or Level 3 assets and liabilities measured on a recurring basis.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Partnership did not have any financial assets and liabilities that were accounted for at fair value as of December 31, 2017, except for those instruments discussed below in “Fair Value of Other Financial Instruments.” The following table sets forth by level within the fair value hierarchy the Partnership’s financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2018.

	Fair Value Measurements at September 30, 2018		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity derivatives - current assets	$ -	$ -	$ -
Commodity derivatives - current liabilities	-	(57,306)	-
Total	$ -	$ (57,306)	$ -

The Level 2 instruments presented in the table above consist of Partnership’s costless collar commodity derivative instruments. The fair value of the Partnership’s derivative financial instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The fair value of the commodity derivatives noted above are included in the Partnership’s consolidated balance sheet in Derivative liability at September 30, 2018. See additional detail in Note 7. Risk Management.

Fair Value of Other Financial Instruments

The carrying value of the Partnership’s 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, current market conditions and short-term maturity of these instruments. In addition, see Note 5. Debt for the fair value discussion on the Partnership’s debt.

Note 7. Risk Management

Participation in the oil and gas industry exposes the Partnership to risks associated with potentially volatile changes in energy commodity prices, and therefore, the Partnership’s future earnings are subject to these risks. As required under the Credit Facility, in September 2018, the Partnership began to utilize derivative contracts to manage the commodity price risk on the Partnership’s future oil production it will produce and sell and to reduce the effect of volatility in commodity price changes to provide a base level of cash flow from operations. All derivative instruments are recorded on the Partnership’s balance sheet as assets or liabilities measured at fair value. As of September 30, 2018, the Partnership’s costless collar derivative instruments were in a net loss position; therefore, a current liability of approximately $0.1 million, which approximates its fair value, was recognized as a Derivative liability on the Partnership’s consolidated balance sheet. The Partnership has not designated its derivative instruments as hedges for accounting purposes and has not entered into such instruments for speculative trading purposes. As a result, when derivatives do not qualify or are not designated as a hedge, the changes in the fair value, in addition to gains or losses on settlements, are recognized on the Partnership’s consolidated statements of operations as a gain or loss on derivative instruments. The Partnership recognized a mark-to-market loss of approximately $0.1 million for the three and nine months ended September 30, 2018, which was recorded on the consolidated statements of operations as Loss on derivatives. No derivative contracts had been settled at September 30, 2018.

The Partnership determines the estimated fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets and quotes from third parties, among other things. The Partnership also performs an internal valuation to ensure the reasonableness of third-party quotes. In consideration of counterparty credit risk, the Partnership assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually-required payments. Additionally, the Partnership considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. See additional discussion above in Note 6. Fair Value of Financial Instruments.

At September 30, 2018, the Partnership had one derivative contract, which was a costless collar, and was used to establish floor and ceiling prices on future anticipated oil production. The Partnership did not pay or receive a premium related to the costless collar agreement. The contract is settled monthly and there were no settlement payables or receivables at September 30, 2018. The follow table reflects the open costless collar agreement as of September 30, 2018.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)	Fair Value of Asset / (Liability) at September 30, 2018
10/01/18 - 10/31/18	NYMEX	42,000	$ 65.00 / 73.10	$ (57,306)

The Partnership's outstanding derivative instrument is covered by an International Swap Dealers Association Master Agreement ("ISDA") entered into with the counterparty. The ISDA may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. The Partnership has netting arrangements with the counterparty that provide for offsetting payables against receivables from separate derivative instruments.

Note 8. Capital Contribution and Partners' Equity

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

As of July 25, 2017, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. In October 2017, the Partnership completed the sale of all common units at $19.00 (2,631,579 common units). In accordance with the prospectus, all subsequent common units are being sold at $20.00 per common unit. As of September 30, 2018, the Partnership had completed the sale of 6.5 million common units for gross proceeds of approximately $127.1 million and proceeds net of offering costs of approximately $118.9 million.

The Partnership intends to continue to raise capital through its best-efforts offering of common units by the Managing Dealer at $20.00. Under the 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 also has Dealer Manager Incentive Fees (defined below) where the Managing Dealer could receive distributions up to an additional 4% of gross proceeds of the common units sold in the Partnership's best-efforts offering as outlined in the prospectus based on the performance of the Partnership. Based on the common units sold through September 30, 2018, the Dealer Manager Incentive Fees are approximately $5.1 million, subject to Payout (defined 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 common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights and will not pay the Dealer Manager Incentive Fees to the Managing Dealer, until Payout occurs.

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

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

- First, (i) to the Record Holders of the Incentive Distribution Rights, 30%; (ii) to the Managing Dealer, the "Dealer Manager Incentive Fees", 30%, until such time as the Managing Dealer receives 4% of the gross proceeds of the common units sold; and (iii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

- Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 60%; and (ii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

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

For the three and nine months ended September 30, 2018, the Partnership paid distributions of $0.349041 and $1.047123 per common unit, or $2.0 million and $4.6 million, respectively. For the three and nine months ended September 30, 2017, the Partnership paid distributions of $0.249316 per common unit, or $0.5 million.

Note 9. 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.

The Partnership will reimburse the General Partner for any costs incurred by the General Partner for certain expenses, which include costs for organizing the Partnership and costs incurred in the offering of the common units. The Partnership has also agreed to pay the General Partner an advisory fee to manage the day-to-day affairs of the Partnership, including serving as an investment advisor and consultant in connection with the acquisition, development, operation and disposition of oil and gas properties and other assets of the Partnership. In accordance with the limited partner agreement, subsequent to the Partnership's first asset purchase, which occurred on February 1, 2018, the Partnership is required to pay quarterly an annual fee of 0.5% of the total gross equity proceeds raised by the Partnership in its best-efforts offering. Based upon the total gross equity proceeds as of September 30, 2018, the management fee for the three and nine months ended September 30, 2018 due to the General Partner is approximately $159,000 and $344,000, respectively. As of September 30, 2018, the accrued management fee due to the General Partner is approximately $344,000, which has been accrued on the consolidated balance sheets in Due to related parties at September 30, 2018 and included in General and administrative expenses on the consolidated statements of operations.

The Partnership also will reimburse the General Partner for certain general and administrative costs. For the three and nine months ended September 30, 2018, approximately $84,000 and $267,000 of general and administrative costs were incurred by a member of the General Partner and will be reimbursed by the Partnership. At September 30, 2018, approximately $84,000 was due to a member of the General Partner and is included in Due to related parties in the consolidated balance sheets.

In January 2018, the Partnership received an advance of $7.0 million from a member of the General Partner to partially fund Acquisition No. 1. The Partnership repaid a member of the General Partner in full in May 2018. The advance did not bear interest and the member of the General Partner did not receive any compensation for the advance.

The Chief Executive Officer and Chief Financial Officer of the Partnership's General Partner are also the Chief Executive Officer and Chief Financial Officer of Energy 11 GP, LLC, the general partner of Energy 11, L.P. ("Energy 11"), a limited partnership that also invests in producing and non-producing oil and gas properties on-shore in the United States. On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11 that gives the Partnership access to Energy 11's personnel and administrative resources, including accounting, asset management and other day-to-day management support. The shared day-to-day costs are split evenly between the two partnerships and any direct third-party costs are paid by the party receiving the services. The shared costs are based on actual costs incurred with no mark-up or profit to the Partnership. The agreement may be terminated at any time by either party upon 60 days written notice.

As noted above, the cost sharing agreement reduces the costs to the Partnership for accounting and asset management services provided through a member of the General Partner. In addition to certain accounting and asset management resources, the Partnership and Energy 11 share the rent expense for leased office space (leased from an affiliate of a member of the general partner of Energy 11) in Oklahoma City, Oklahoma along with the compensation due to the President of Energy 11's general partner. For the three and nine months ended September 30, 2018, approximately $64,000 and $175,000, respectively, of expenses subject to the cost sharing agreement were incurred by the Partnership and will be reimbursed to Energy 11. At September 30, 2018, approximately $64,000 is due from the Partnership to Energy 11 and is included in Due to related parties in the consolidated balance sheets.

Note 10. Subsequent Events

In October 2018, the Partnership declared and paid $0.7 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In October 2018, the Partnership closed on the issuance of approximately 0.6 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $11.8 million and proceeds net of selling and marketing costs of approximately $11.1 million. The Partnership used the net proceeds to reduce its outstanding debt obligations discussed in Note 5. Debt. The Partnership paid $5.0 million against the Credit Facility, reducing the outstanding balance to $39.5 million. Therefore, because the outstanding balance of the Credit Facility was reduced below $40.0 million, the Partnership is no longer required to make monthly mandatory principal repayments. The Partnership also paid $5.0 million against the Term Loan, reducing the outstanding balance to $10.0 million.

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;
- the Partnership's business strategy;
- estimated future distributions;
- 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" in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017 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 and acquisition 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, 2017.

Overview

Energy Resources 12, L.P. (the "Partnership") was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on December 30, 2016. 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 $350,000,001 of capital, consisting of 17,631,579 common units. The Partnership's Registration Statement on Form S-1 (File No. 333-216891) was declared effective by the Securities and Exchange Commission on May 17, 2017. As of July 25, 2017, the Partnership completed the sale of the minimum offering of common units for gross proceeds of approximately $25 million. Additionally upon closing of the minimum offering, the organizational limited partner withdrew its initial capital contribution of $990 and Energy Resources 12 GP, LLC (the "General Partner") received Incentive Distribution Rights (defined below). As of September 30, 2018, the Partnership had completed the sale of 6.5 million common units for gross proceeds of approximately $127.1 million and proceeds net of offering costs of approximately $118.9 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 primarily oil and gas properties located onshore in the United States. On February 1, 2018, the Partnership completed its first purchase ("Acquisition No. 1") in the Williston Basin of North Dakota, acquiring, at closing, an approximate average 3.1% non-operated working interest in 204 producing wells, 30 wells in various stages of the drilling and completion process and additional future development locations, predominantly in McKenzie, Dunn, McLean and Mountrail counties of North Dakota (collectively, the "Bakken Assets"), for approximately $87.5 million. On August 31, 2018, the Partnership closed on its second asset purchase ("Acquisition No. 2"), acquiring an additional non-operated working interest in the Bakken Assets for approximately $82.5 million, subject to customary adjustments. Prior to these acquisitions, the Partnership owned no oil and natural gas assets. The Partnership utilized proceeds from its ongoing best-efforts offering and available financing to close on the acquisitions. See further discussion below under Liquidity and Capital Resources.

As a result of these acquisitions and completed drilling during the period of ownership, as of September 30, 2018, the Partnership had an approximate 6.0% non-operated working interest in the Bakken Assets, consisting of 243 producing wells, 47 wells in various stages of the drilling and completion process and additional future development locations. The Bakken Assets are located in the Bakken Shale formation, including the Antelope, Spotted Horn, Squaw Creek and Reunion Bay fields. The Bakken Shale and its close geologic cousin, the Three Forks Shale, are found in the Williston Basin, centered in North Dakota and are two of the largest oil fields in the U.S. 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.

The Bakken Assets are operated by 14 third-party operators, including WPX Energy (NYSE: WPX), Marathon Oil (NYSE: MRO), EOG Resources (NYSE: EOG) and Continental Resources (NYSE: CLR).

Current Price Environment

Oil, natural gas and natural gas liquids ("NGL") prices are determined by many factors outside of the Partnership's control. Energy commodity prices are historically volatile and may continue to be into the future. Since February 2018, monthly average oil prices (based on daily settlements of monthly contracts traded on the NYMEX) ranged from a low of $62.23 per barrel in February 2018 to a high of $70.98 in July 2018. The monthly average of $70.98 per barrel of oil in July 2018 represented the highest monthly average since November 2014. Since February 2018, monthly averages for natural gas prices have ranged from $2.67 per MMBtu in February 2018 to $3.00 per MMBtu in September 2018.

The average daily NYMEX prices for oil and natural gas for the three months ended September 30, 2018 were $69.57 per barrel of oil and $2.93 per MMBtu of natural gas, respectively. The average daily NYMEX prices for oil and natural gas since the Partnership's first acquisition on February 1, 2018 were $67.25 per barrel of oil and $2.84 per MMBtu of natural gas, respectively.

Factors contributing to world-wide commodity pricing volatility include real or perceived geopolitical risks in oil-producing regions of the world, particularly the Middle East; forecasted levels of global economic growth combined with forecasted global supply; supply levels of oil and natural gas due to exploration and development activities in the United States; actions taken by the Organization of Petroleum Exporting Countries; and the strength of the U.S. dollar in international currency markets. 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 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. Since Acquisition No. 1, the Partnership has participated in the drilling of 86 wells.

Results of Operations

The Partnership closed on its first and second purchases of the Bakken Assets on February 1, 2018 and August 31, 2018, respectively. Other than the payment of fees and expenses described herein, the Partnership had no other operations prior to the acquisition of the Bakken Assets. Because the Partnership had no revenues in fiscal 2017, there is no comparison of the Partnership's results of operations for the three and nine months ended September 30, 2018 to the Partnership's results of operations for the three and nine months ended September 30, 2017, except as otherwise indicated below.

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 and (3) production costs per BOE. The following table is a summary of the results from operations, including production, of the Partnership's non-operated working interest in the Bakken Assets for the three months ended September 30, 2018 and the eight-month period from February 1, 2018 to September 30, 2018 (reflecting the period of ownership of Acquisition No. 1).

	Three Months Ended September 30,		Eight Months Ended September 30,	
	2018	Percent of Revenue	2018	Percent of Revenue
Total revenues	$ 5,503,706	100.0%	$ 16,531,881	100.0%
Production expenses	945,233	17.2%	3,213,860	19.4%
Production taxes	548,574	10.0%	1,487,100	9.0%
Depreciation, depletion, amortization and accretion	1,024,676	18.6%	3,040,755	18.4%
General and administrative expenses	360,382	6.5%	1,104,416	6.7%
Sold production (BOE):				
Oil	74,243		237,063	
Natural gas	11,727		35,131	
Natural gas liquids	7,747		28,884	
Total	93,717		301,078	
Average sales price per unit:				
Oil (per Bbl)	$ 68.19		$ 64.42	
Natural gas (per Mcf)	3.59		2.98	
Natural gas liquids (per Bbl)	24.32		21.92	
Combined average sales price (per BOE)	58.73		54.91	
Average cost per BOE:				
Production expenses	10.09		10.67	
Production taxes	5.85		4.94	
Depreciation, depletion, amortization and accretion	10.93		10.10	

Oil, Natural Gas and NGL Revenues

For the three months ended September 30, 2018, revenues for oil, natural gas and NGL sales were $5.5 million. Revenues for the sale of crude oil were $5.1 million, which resulted in a realized price of $68.19 per barrel. Revenues for the sale of natural gas were $0.3 million, which resulted in a realized price of $3.59 per Mcf. Revenues for the sale of NGLs were $0.2 million, which resulted in a realized price of $24.32 per BOE of production.

For the eight months from February 1, 2018 to September 30, 2018, revenues for oil, natural gas and NGL sales were $16.5 million. Revenues for the sale of crude oil were $15.3 million, which resulted in a realized price of $64.42 per barrel. Revenues for the sale of natural gas were $0.6 million, which resulted in a realized price of $2.98 per Mcf. Revenues for the sale of NGLs were $0.6 million, which resulted in a realized price of $21.92 per BOE of production.

The Partnership's sold production for the Bakken Assets was approximately 1,020 BOE and 1,245 BOE per day for the three months ended September 30, 2018 and for the eight-month period from February 1, 2018 to September 30, 2018. Production volumes per day declined during the third quarter primarily due to the timing of well completions. During the first and second quarters of 2018, approximately 36 new wells were completed. Production from these wells was maximized in the second quarter of 2018, which contributed to a significant increase in sold production during the second quarter of 2018. Only three wells were completed during the third quarter of 2018. New wells often have high levels of production immediately following completion, then decline to more consistent levels.

Production is dependent on the investment in existing wells and the development of new wells. As noted above, the Partnership will experience natural production declines in the months following the completion of new wells. As further discussed in Liquidity and Capital Resources: Oil and Natural Gas Properties below, the Partnership has 47 wells currently in various stages of drilling and completion and therefore, expects production volume to increase in conjunction with the completion of those wells. However, if the Partnership or its operators are unable or it is not cost beneficial to continue to invest in existing wells or develop new wells, production will 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, along with the gathering and processing contracts in effect for the extraction, transportation and treatment of natural gas.

Production expenses for the three months ended September 30, 2018 were $0.9 million, and production expenses per BOE were $10.09. Production expenses for the eight months from February 1, 2018 to September 30, 2018 were $3.2 million, and production expenses per BOE were $10.67.

Production Taxes

Taxes on the production and extraction of oil and gas are regulated and set by North Dakota tax authorities. Taxes on the sale of gas and NGL products are less than taxes levied on the sale of oil. Production taxes for the three months ended September 30, 2018 were $0.5 million (10.0% of revenue). Production taxes for the eight months from February 1, 2018 to September 30, 2018 were $1.5 million (9.0% of revenue).

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. The Partnership's DD&A for the three months ended September 30, 2018 was $1.0 million, and DD&A per BOE of production was $10.93. DD&A for the eight months from February 1, 2018 to September 30, 2018 was $3.0 million, and DD&A per BOE of production was $10.10.

General and Administrative Costs

The principal components of general and administrative expense are accounting, legal, advisory and consulting fees. General and administrative costs for the three months ended September 30, 2018 and 2017 were $0.4 million and $28,226, respectively. General and administrative expenses for the nine months ended September 30, 2018 and 2017 were $1.1 million and $49,331, respectively. General and administrative expenses for the three and nine months ended September 30, 2018 exceeded those of the prior year due to the Partnership raising funds through its ongoing offering and the acquisitions of non-operated working interest in the Bakken Assets in February and August 2018, resulting in a rise in year-to-date accounting, legal and consulting and advisory fees.

Loss on Derivatives

In September 2018, the Partnership began to utilize derivative contracts to manage the commodity price risk on the Partnership's future oil production. As of September 30, 2018, the Partnership's derivative contract (costless collar) was in a loss position based upon the contract's estimated fair market value at the balance sheet date. Based upon the estimated fair value of the derivative contract as of September 30, 2018, the Partnership recorded a mark-to-market loss of approximately $57,000. Changes in the fair value of the unsettled derivative contracts represent mark-to-market gains and losses and are recorded on the Partnership's consolidated statements of operations. The mark-to-market loss recorded by the Partnership does not represent an actual settlement and no payment was made to the counterparty during the third quarter of 2018. Under the Credit Facility, the Partnership is required to maintain a risk management program, covering at least 80% of the Partnership's total monthly production of oil and natural gas through March 31, 2019, and at least 50% thereafter. See further discussion in "Note 7. Risk Management" in Part I, Item 1 of this Form 10-Q.

Interest Expense, net

Interest expense, net for the three and nine months ended September 30, 2018 was $0.5 million and $0.9 million, respectively. Interest income, net, for the three and nine months ended September 30, 2017 was $40,750 and $39,645, respectively. The primary component of Interest expense, net, during the three and nine months ended September 30, 2018 was interest expense on the Term Loan and Credit Facility, as discussed below in Liquidity and Capital Resources: Financing.

Supplemental Non-GAAP Measure

The Partnership uses "Adjusted EBITDAX", defined as Earnings before (i) interest expense, net; (ii) income taxes; (iii) depreciation, depletion, amortization and accretion; (iv) exploration expenses; and (v) (gain)/loss on the mark-to-market of derivative instruments, 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. Adjusted EBITDAX is not necessarily indicative of funds available to fund the Partnership's cash needs, including its ability to make cash distributions. Although Adjusted EBITDAX, as calculated by the Partnership, may not be comparable to Adjusted 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 Adjusted 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 operators.

The following table reconciles the Partnership's GAAP net income to Adjusted EBITDAX for the three and nine months ended September 30, 2018.

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Net income	$ 2,087,725	$ 6,776,585
Interest expense, net	479,810	851,859
Depreciation, depletion, amortization and accretion	1,024,676	3,040,755
Exploration expenses	-	-
Non-cash loss on mark-to-market of derivatives	57,306	57,306
Adjusted EBITDAX	$ 3,649,517	$ 10,726,505

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 9. Related Parties" in Part I, Item 1 of this Form 10-Q.

Liquidity and Capital Resources

The Partnership's principal source of liquidity will be the proceeds of the best-efforts offering, the cash flow generated from properties the Partnership has acquired and availability, if any, under the Partnership's revolving credit facility discussed below. The Partnership anticipates that cash on hand, cash flow from operations, availability under the revolving credit facility and proceeds of the best-efforts offering will be adequate to meet its liquidity requirements for at least the next 12 months, including completing capital expenditures discussed below. If the Partnership is unable to raise sufficient proceeds from its ongoing best-efforts offering or obtain additional financing, it may default on its financial covenants under the revolving credit facility and be unable to pay distributions or participate in the drilling programs as proposed by the operators of the Bakken Assets.

Financing

On January 16, 2018, the Partnership entered into a loan agreement with Bank of America, N.A. ("BOA"), which provides for an unsecured term loan (the "Term Loan") of $25 million. The Term Loan bears interest at a variable rate based on the London Inter-Bank Offered Rate (LIBOR) plus a margin of 2.00%. Interest is payable monthly.

The Term Loan proceeds were used in closing on Acquisition No. 1, as described above. Under the terms of the loan agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. However, as discussed below, prepayments are limited under the terms of the Credit Facility. Glade M. Knight and David S. McKenney, the General Partner's Chief Executive Officer and Chief Financial Officer, respectively, have guaranteed repayment of the Term Loan and did not and will not receive any consideration in exchange for providing this guarantee. The Term Loan contains mandatory prepayment requirements, customary affirmative and negative covenants and events of default.

On August 31, 2018, the Partnership entered into a loan agreement ("Loan Agreement") with Simmons Bank as administrative agent and the lenders party thereto (collectively, the "Lender"), which provides for a revolving credit facility (the "Credit Facility") with an initial commitment amount of $60 million (the "Revolver Commitment Amount"), subject to borrowing base restrictions. The commitment amount may be increased up to $100 million with Lender approval. At closing, the Partnership paid an origination fee of 0.50% of the Revolver Commitment Amount, or $300,000, and is subject to additional origination fees of 0.50% for any increase to the commitment made in excess of the Revolver Commitment Amount. The Partnership is also required to pay an unused facility fee at an annual rate of 0.50% on the unused portion of the Revolver Commitment Amount, based on the amount of borrowings outstanding during a quarter. The maturity date is August 31, 2021 ("Maturity Date").

Under the Loan Agreement, the initial borrowing base is $60 million. However, the borrowing base is subject to redetermination semi-annually based upon the Lender's analysis of the Partnership's proven oil and natural gas reserves. In addition, the Partnership's monthly mandatory principal payments (discussed below) reduce the Partnership's borrowing base; the borrowing base minimum is $40 million. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time. The interest rate, subject to certain exceptions, is equal to the London Inter-Bank Offered Rate (LIBOR) plus a margin ranging from 2.75% to 3.75%, depending upon the Partnership's borrowing base utilization, as calculated under the terms of the Loan Agreement. In addition to monthly interest payments on the outstanding principal balance of the note, the Partnership (subject to certain exceptions) must make mandatory principal payments monthly in an amount equal to 100% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the note is reduced to $40 million. The Partnership is required to reduce the outstanding principal amount of the note to at or below $40 million by March 15, 2019.

At closing, the Partnership borrowed $60.0 million. The proceeds were used to fund the purchase of Acquisition No. 2 described above and to pay closing costs. Subject to availability, the Credit Facility may also provide additional liquidity for future capital investments, including the drilling and completion of proposed wells by the operators of the Partnership's properties, and other corporate working capital requirements. Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. The Credit Facility is secured by a mortgage and first lien position on at least 90% of the Partnership's producing wells.

The Credit Facility contains mandatory prepayment requirements (including those described above), customary affirmative and negative covenants and events of default. The financial covenants as defined in the Loan Agreement include:

- a maximum leverage ratio
- a minimum current ratio
- maximum distributions

The Partnership was in compliance with the applicable covenants at September 30, 2018.

As a condition to closing on the Credit Facility, the Partnership was required to extend the maturity of Term Loan with BOA to April 15, 2019 from its original maturity date of January 15, 2019. Also, BOA was required to consent to the Partnership entering into the Credit Facility. The Partnership and BOA amended the Term Loan on August 16, 2018, whereby BOA gave consent and extended the maturity date. Under the Credit Facility, no principal payments can be made on the BOA loan until the outstanding balance on the Credit Facility is less than $40.0 million.

As of September 30, 2018, the outstanding balance and the applicable interest rate on the Term Loan were $15.0 million and 4.25%, respectively. As of September 30, 2018, the outstanding balance and the applicable interest rate on the Credit Facility were $44.5 million and 5.71%, respectively. The Partnership intends to use proceeds from its best-efforts offering and cash flow from operations to meet its mandatory prepayments under the Credit Facility and to repay the Term Loan.

Partners' Equity

The Partnership intends to continue to raise capital through its best-efforts offering of common units by the Managing Dealer at $20.00. Under the 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 also has Dealer Manager Incentive Fees (defined below) where the Managing Dealer could receive distributions up to an additional 4% of gross proceeds of the common units sold in the Partnership's best-efforts offering as outlined in the prospectus based on the performance of the Partnership. Based on the common units sold through September 30, 2018, the Dealer Manager Incentive Fees are approximately $5.1 million, subject to Payout (defined below). As of September 30, 2018, the Partnership had completed the sale of 6.5 million common units for gross proceeds of approximately $127.1 million and proceeds net of offering costs of approximately $118.9 million.

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 and will not pay the Dealer Manager Incentive Fees to the Managing Dealer, until Payout occurs.

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

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

- First, (i) to the Record Holders of the Incentive Distribution Rights, 30%; (ii) to the Managing Dealer, the "Dealer Manager Incentive Fees", 30%, until such time as the Managing Dealer receives 4% of the gross proceeds of the common units sold; and (iii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

- Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 60%; and (ii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

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

For the three and nine months ended September 30, 2018, the Partnership paid distributions of $0.349041 and $1.047123 per common unit, or $2.0 million and $4.6 million, respectively. For the three and nine months ended September 30, 2017, the Partnership paid distributions of $0.249316 per common unit, or $0.5 million. The Partnership generated $6.8 million in cash flow from operations for the nine months ended September 30, 2018.

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 intended rate of distribution will be based on its ability to increase its cash generated from operations. As there can be no assurance that the assets acquired by the Partnership will provide income at this level, there can be no assurance as to the classification or duration of distributions at the current rate. Proceeds of the offering which are distributed are not available for investment in properties.

Oil and Natural Gas Properties

The Partnership incurred approximately $2.7 million and $5.6 million in capital expenditures for the three months ended September 30, 2018 and for the period from February 1, 2018 to September 30, 2018. The Partnership expects to invest approximately $5.0 to $8.0 million in capital expenditures during the remainder of 2018 and a total of approximately $22 million in capital expenditures through the middle of 2019. In addition, the Partnership anticipates that it may be obligated to invest an additional $110 to $120 million in drilling capital expenditures through 2023 to retain its approximate 6.0% working interest in the Bakken Assets without becoming subject to non-consent penalties under the joint operating agreements governing the Bakken Assets.

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 the remainder of 2018 and 2019. 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 proceeds from its ongoing best-efforts offering, cash provided by operating activities, cash on hand and availability, if any, under the Credit Facility. If an 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.

Subsequent Events

In October 2018, the Partnership declared and paid $0.7 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In October 2018, the Partnership closed on the issuance of approximately 0.6 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $11.8 million and proceeds net of selling and marketing costs of approximately $11.1 million. The Partnership used the net proceeds to reduce its outstanding debt obligations discussed in “Financing” above. The Partnership paid $5.0 million against the Credit Facility, reducing the outstanding balance to $39.5 million. Therefore, because the outstanding balance of the Credit Facility was reduced below $40.0 million, the Partnership is no longer required to make monthly mandatory principal repayments. The Partnership also paid $5.0 million against the Term Loan, reducing the outstanding balance to $10.0 million.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information regarding the Partnership’s hedging programs to mitigate commodity risks is contained in Item 1 – Financial Statements (Unaudited) and Notes to Consolidated Financial Statements: Note 7. Risk Management and Item 2 – Management’s Discussion and Analysis of Financial Condition and Results of Operations, appearing elsewhere within this Quarterly Report on Form 10-Q.

The Partnership also has a variable interest rate on its Credit Facility that is subject to market changes in interest rates. Information regarding the Partnership’s Credit Facility is contained in Item 1 – Financial Statements (Unaudited) and Notes to Consolidated Financial Statements: Note 5. Debt and Item 2 – Management’s Discussion and Analysis of Financial Condition and Results of Operations, appearing elsewhere within this Quarterly Report on Form 10-Q.

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, 2018 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, 2018 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 Partnership's 2017 Annual Report on Form 10-K. There have been no material changes to the risk factors previously disclosed in the 2017 Form 10-K.

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

The Partnership's Registration Statement on Form S-1 (File No. 333-216891) was declared effective by the Securities and Exchange Commission on May 17, 2017. Under the public offering the Partnership made under the Registration Statement (as supplemented), 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 $350,000,001 of capital, consisting of 17,631,579 common units. As of September 30, 2018, the Partnership had completed the sale of 6,485,774 common units for total gross proceeds of $127.1 million and proceeds net of offering costs including selling commissions and marketing expenses of $118.9 million. As of September 30, 2018, 11,145,805 common units remained unsold. The offering will expire on May 17, 2019, unless extended by the General Partner, provided that the offering will be terminated if all of the common units are sold before then. The public offering is being made through David Lerner Associates, Inc. (the "Managing Dealer"). In October 2017, the Partnership completed the sale of 2,631,579 common units at $19.00 per common unit, or $50 million. All subsequent common units are being sold at $20.00 per common unit.

Under the Partnership's 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 also has Dealer Manager Incentive Fees, 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 September 30, 2018, the Dealer Manager Incentive Fees are up to approximately $5.1 million.

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

Use of Proceeds

The following table sets forth information concerning the on-going best-efforts offering and the use of proceeds from the offering as of September 30, 2018.

Units Registered							
	2,631,579	Units	$	19.00	per unit	$	50,000,001
	15,000,000	Units	$	20.00	per unit		300,000,000
Totals:	17,631,579	Units				$	350,000,001
Units Sold							
	2,631,579	Units	$	19.00	per unit	$	50,000,001
	3,854,195	Units	$	20.00	per unit		77,083,899
Totals:	6,485,774	Units				$	127,083,900

Expenses of Issuance and Distribution of Units		
1. Underwriting commissions	$	7,625,034
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		588,860
Total Expenses of Issuance and Distribution of Common Shares		8,213,894
Net Proceeds to the Partnership	$	118,870,006
1. Purchase of oil, gas and natural gas liquids properties (net of debt, proceeds and repayment including interest and acquisition costs)	$	112,679,934
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		6,190,072
5. Fees and expenses of third parties		-
6. Other		-
Total Application of Net Proceeds to the Partnership	$	118,870,006

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
2.1	Purchase and Sale Agreement dated June 29, 2018 by and between Energy Resources 12 Operating Company, LLC, as Purchaser, and Bruin E&P Non-Op Holdings, LLC, as Seller (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed on July 6, 2018).
10.1	Loan Agreement between Bank of America, N.A. and Energy Resources 12, L.P. dated January 16, 2018 (incorporated by reference from Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on January 17, 2018).
10.2	Cost Sharing Agreement between Energy Resources 12, L.P., Energy 11, L.P. and Energy 11 Management, LLC, dated January 31, 2018 (incorporated by reference from Exhibit 10.7 to Post-Effective Amendment No. 1 to the Partnership's Registration Statement on Form S-1 filed on February 1, 2018).
10.3	Advisory and Administration Agreement dated June 29, 2018 by and between Energy Resources 12 Operating Company, LLC, Energy Resources 12, L.P., and Regional Energy Investors, LP (incorporated by reference from Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on July 6, 2018).
10.4	Revolver Loan Agreement dated as of August 31, 2018 between and among Energy Resources 12, L.P. and Energy Resources 12 Operating Company, LLC, collectively, the Borrower, and Simmons Bank, as Administrative Agent and Letter of Credit Issuer and the Lenders Signatory Party Hereto, collectively, the Lenders (incorporated by reference from Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on September 5, 2018).
10.5	Loan Agreement Amendment and Consent, made as of August 16, 2018, between Bank of America, N.A. and Energy Resources 12, L.P. (incorporated by reference from Exhibit 10.2 to the Partnership's Current Report on Form 8-K filed on September 5, 2018).
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 Resources 12, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2018 formatted in XBRL (eXtensible Business Reporting Language): (i) the Balance Sheets, (ii) the Statements of Operations, (iii) the Statement 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 Resources 12, L.P.

By: Energy Resources 12 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 14, 2018

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 Resources 12, 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 14, 2018

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 Quarterly Report on Form 10-Q of Energy Resources 12, 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 14, 2018

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, 2018 of Energy Resources 12, 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 14, 2018

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, 2018 of Energy Resources 12, 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 14, 2018

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