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ENERGY RESOURCES 12, L.P. (Filer) CIK: 0001696088

Document And Entity Information - USD ($)	12 Months Ended		
	Dec. 31, 2017	Feb. 22, 2018	Jun. 30, 2017
Document and Entity Information [Abstract]			
Entity Registrant Name	ENERGY RESOURCES 12, L.P.		
Document Type	10-K		
Current Fiscal Year End Date	--12-31		
Entity Common Stock, Shares Outstanding		3,600,462	
Entity Public Float			$ 0
Amendment Flag	false		
Entity Central Index Key	0001696088		
Entity Current Reporting Status	Yes		
Entity Voluntary Filers	No		
Entity Filer Category	Smaller Reporting Company		
Entity Well-known Seasoned Issuer	No		
Document Period End Date	Dec. 31, 2017		
Document Fiscal Year Focus	2017		
Document Fiscal Period Focus	FY		

Balance Sheets - USD ($)	Dec. 31, 2017	Dec. 31, 2016
Assets		
Cash	$ 46,859,728	$ 1,000
Deposit for potential acquisition	8,750,000	0
Deferred acquisition costs	4,884,208	0
Deferred offering costs	0	22,975
Total Assets	60,493,936	23,975
Liabilities		
Accounts payable and accrued expenses	5,448,409	23,245
Total Liabilities	5,448,409	23,245
Partners' Equity		
Limited partners' interest (3,191,231 and 0 common units issued and outstanding, respectively)	55,045,742	723
General partner's interest	(215)	7
Total Partners' Equity	55,045,527	730
Total Liabilities and Partners' Equity	$ 60,493,936	$ 23,975

Balance Sheets (Parentheticals) - shares	Dec. 31, 2017	Dec. 31, 2016
Limited partners' interest, common units issued	3,191,231	0
Limited partners' interest, common units outstanding	3,191,231	0

Statements of Operations - USD ($)		12 Months Ended
	Dec. 31, 2016	Dec. 31, 2017
Revenue	$ 0	$ 0
Transaction costs	0	525,000
General and administrative expenses	270	99,410
Operating loss	(270)	(624,410)

Interest income, net	0	114,163
Net loss	$ (270)	$ (510,247)
Basic and diluted net income (loss) per common unit (in Dollars per share)	$ 0	$ (0.48)
Weighted average common units outstanding - basic and diluted (in Shares)	0	1,067,941

Statement of Partners' Equity - USD ($)	Total	Limited Partner [Member]	General Partner [Member]
Balance at Dec. 30, 2016	$ 1,000	$ 990	$ 10
Net loss	(270)	(267)	(3)
Balance at Dec. 31, 2016	730	723	7
Net proceeds from issuance of common units	57,014,432	57,014,432	0
Distributions to organizational limited partner	(990)	(990)	0
Distributions declared and paid to common units	(1,458,398)	(1,458,398)	0
Net loss	(510,247)	(510,025)	(222)
Balance at Dec. 31, 2017	$ 55,045,527	$ 55,045,742	$ (215)

Statement of Partners' Equity (Parentheticals)	12 Months Ended
	Dec. 31, 2017 $ / shares
Distributions declared and paid per unit	$ 0.598357

Statement of Cash Flows - USD ($)		12 Months Ended
	Dec. 31, 2016	Dec. 31, 2017
Cash flow from operating activities:		
Net loss	$ (270)	$ (510,247)
Changes in operating assets and liabilities:		
Deferred acquisition costs	0	(4,190)
Accounts payable and accrued expenses	270	560,832
Net cash used in operating activities	0	46,395
Cash flow from investing activities		
Deposit for acquisition of oil, natural gas and natural gas liquids properties	0	(8,750,000)
Net cash used in investing activities	0	(8,750,000)
Cash flow from financing activities		
Net proceeds related to issuance of common units	0	57,020,731
Net proceeds from line of credit	0	229,000
Payments on line of credit	0	(229,000)
Distributions paid to limited partners	0	(1,458,398)
Net cash provided by financing activities	0	55,562,333
Increase in cash and cash equivalents	0	46,858,728
Cash and cash equivalents, beginning of period	1,000	1,000
Cash and cash equivalents, end of period	1,000	46,859,728
Interest paid	0	1,420
Supplemental information:		
Accrued deferred costs for potential acquisition	0	4,880,018
Accrued deferred offering costs	$ 22,975	$ 0

Partnership Organization	12 Months Ended
	Dec. 31, 2017
Disclosure Text Block [Abstract]	
Organization, Consolidation and Presentation of Financial Statements Disclosure [Text Block]	**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.

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

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.

Summary of Significant Accounting Policies	12 Months Ended Dec. 31, 2017
Accounting Policies [Abstract]	
Significant Accounting Policies [Text Block]	(see below)

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

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

Cash and Cash Equivalents

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

Offering Costs

The Partnership is raising capital through an on-going best-efforts offering of units by 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 December 31, 2017, the Partnership had sold 3.2 million common units for gross proceeds of $61.2 million and proceeds net of offering costs of $57.0 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.

Income Tax

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

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

Property and Depreciation, Depletion and Amortization

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

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

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

Impairment

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

Accounting for Asset Retirement Obligations

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

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

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues will be recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of 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 will not operate its oil and natural gas properties and, therefore, will receive actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well will be 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 will adjust the estimated accruals of revenue to actual production in the period actual production is determined.

Net Loss per Common Unit

Basic net loss per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted net loss per 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 year ended December 31, 2017. As a result, basic and diluted outstanding common units were the same. There were no outstanding common units for the period ended December 31, 2016. The Incentive Distribution Rights (as discussed in Note 3) are not included in net loss per common unit until such time that it is probable Payout (as discussed in Note 3) would occur.

Recently Adopted Accounting Standards

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2017-01, Business Combinations (Topic 805), which amends the existing accounting standards to clarify the definition of a business and assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, including interim periods within those periods, and should be applied prospectively on or after the effective date. The Partnership adopted this standard effective January 1, 2017.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), that amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. Throughout 2016, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 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.

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. The Partnership is still evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

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 plans to adopt this standard in the first quarter of 2018. As of December 31, 2017, the Partnership has no outstanding hedge positions; therefore, the adoption of this standard is not expected to have a material impact on the Partnership's consolidated financial statements.

Oil and Gas Investments	12 Months Ended
	Dec. 31, 2017
Oil and Gas Property [Abstract]	
Oil and Gas Properties [Text Block]	**Note 3. Oil and Gas Investments** On November 21, 2017, Energy Resources 12 Operating Company, LLC ("Buyer"), a wholly-

owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement ("Purchase Agreement") with Bruin E&P Non-Op Holdings, LLC ("Seller"), for the potential purchase of Seller's interest in certain non-operated oil and gas properties and the related rights, resulting in an approximate average 3.1% non-operated working interest in approximately 204 existing producing wells and approximately 547 future development locations, predominantly in McKenzie, Dunn, McLean and Mountrail counties of North Dakota (collectively, the "Bakken Assets"). The Buyer closed on the purchase of the Bakken Assets on February 1, 2018. The Buyer will not be the operator of the Bakken Assets; the current, experienced operators will continue to operate the Bakken Assets on behalf of the Buyer and other working interest owners.

Pursuant to the Purchase Agreement, the purchase price for the Bakken Assets is $87.5 million. On November 21, 2017, the Partnership, on behalf of the Buyer, funded a deposit of 10% of the purchase price, or $8.75 million, to the Seller that was applied toward the purchase price at closing. The final settlement purchase price is subject to the customary post-closing adjustments, as defined and identified in the Purchase Agreement.

The closing of the Purchase Agreement was subject to the satisfaction of a number of required conditions which, at December 31, 2017, remained unsatisfied under the Purchase Agreement. Consummation of the acquisition was subject to the Buyer's satisfactory completion of the review of title, environmental investigations, financial analysis and geological analysis, obtaining sufficient financing to fund the purchase price and other due diligence.

The Partnership has engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting the Buyer through closing and post-closing of the Purchase Agreement. The Partnership will pay REI a total of approximately $5.3 million for its advisory and consulting services. REI is also entitled to a fee of 5% of the gross sales price in the event the Buyer 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 Note 4 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 6. Related Parties below for additional information.

The acquisition-related costs incurred for legal, accounting and environmental review services through December 31, 2017 of approximately $4.9 million were included in Deferred costs for potential acquisition on the Partnership's consolidated balance sheets. Approximately $0.5 million of the fee payable to REI related to due diligence work on potential acquisitions that were not pursued, and therefore, were recorded as Transaction costs in the Partnership's consolidated statements of operations.

Capital Contribution and Partners' Equity	12 Months Ended Dec. 31, 2017
Partners' Capital Notes [Abstract]	
Partners' Capital Notes Disclosure [Text Block]	**Note 4. Capital Contribution and Partners' Equity**

Note 4. 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. As of December 31, 2017, the Partnership had completed the sale of 3,191,231 common units for gross proceeds of approximately $61.2 million and proceeds net of offering costs of approximately $57.0 million. 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.

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 December 31, 2017, the Dealer Manager Incentive Fees are approximately $2.4 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 year ended December 31, 2017, the Partnership paid distributions of $0.598357 per common unit, or $1.5 million.

Line of Credit	12 Months Ended Dec. 31, 2017
Debt Disclosure [Abstract]	
Debt Disclosure [Text Block]	**Note 5. Line of Credit** In February 2017, the Partnership obtained an unsecured line of credit with Bank of America in the principal amount of $500,000 to fund some of its offering and operating costs. On July 25, 2017, the Partnership repaid the outstanding balance on the line of credit of $229,000, which bore interest at a variable rate based on the London InterBank Offered Rate (LIBOR), using proceeds from the sale of common units without a prepayment premium or penalty. Glade M. Knight, the General Partner's Chief Executive Officer, and David S. McKenney, the General Partner's Chief Financial Officer, had guaranteed repayment of the line of credit and did not receive any consideration in exchange for providing this guarantee.

Related Parties	12 Months Ended Dec. 31, 2017
Related Party Transactions [Abstract]	
Related Party Transactions Disclosure [Text Block]	**Note 6. 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 has 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. Subsequent to the Partnership's first asset purchase, the Partnership will pay quarterly an annual fee of 0.5% of the total gross equity proceeds raised by the Partnership in its offering as outlined in the prospectus. The fees paid to the General Partner will be expensed as incurred. In addition, the Partnership will also reimburse the General Partner for any costs incurred by the General Partner in organizing the Partnership or incurred in the offering of the common units. For the year ended December 31, 2017, approximately $57,000 of general and administrative costs were incurred by a member of the General Partner and have been or will be reimbursed by the Partnership. At December 31, 2017, approximately $34,000 was due to a member of the General Partner. See discussion above in Note 3. Oil and Gas Investments regarding costs incurred and payable to a related party for due diligence and advisory services provided on the acquisition of the Bakken Assets. 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"). The Partnership has and anticipates that it will share accounting and

administrative resources, including personnel, with Energy 11 to ensure effective staffing of the Partnership. The cost of these accounting and administrative resources will be shared between the partnerships. See discussion below in Note 7. Subsequent Events on the cost sharing agreement.

Subsequent Event	12 Months Ended Dec. 31, 2017
Subsequent Events [Abstract]	
Subsequent Events [Text Block]	**Note 7. Subsequent Events** In January 2018, the Partnership closed on the issuance of approximately 0.2 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $4.2 million and proceeds net of selling and marketing costs of approximately $4.0 million. In January 2018, the Partnership declared and paid $0.3 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units. On January 16, 2018, the Partnership entered into a loan agreement with Bank of America, N.A., as the lender, for an unsecured 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%. The maturity date is January 15, 2019. On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11 to provide access to Energy 11's personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for the Partnership. The shared day-to-day costs will be split evenly between the two partnerships and any direct third-party costs will be paid by the party receiving the services. The shared costs will be based on actual costs incurred with no mark-up or profit for Energy 11. The agreement may be terminated at any time by either party upon 60 days written notice. The officers and members of the Partnership's General Partner are also officers and members of the general partner of Energy 11. On February 1, 2018, the Partnership, through its wholly-owned subsidiary, closed on the acquisition of Seller's interest in the Bakken Assets discussed in Note 3. Oil and Gas Investments above. The purchase price of $87.5 million, subject to customary adjustments, was funded by net proceeds from the Partnership's ongoing public offering, proceeds from the unsecured term loan discussed above and an advance from a member of the General Partner of $7.0 million. The advance does not bear interest and the member of the General Partner did not receive any compensation for the advance. The unsecured term loan and the advance are planned to be repaid with future proceeds from the Partnership's ongoing public offering. In February 2018, the Partnership closed on the issuance of approximately 0.2 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $4.0 million and proceeds net of selling and marketing costs of approximately $3.7 million. In February 2018, the Partnership declared and paid $0.4 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

Accounting Policies, by Policy (Policies)	12 Months Ended Dec. 31, 2017
Accounting Policies [Abstract]	
Basis of Accounting, Policy [Policy Text Block]	*Basis of Presentation* The accompanying financial statements of the Partnership have been prepared in accordance with United States generally accepted accounting principles ("US GAAP").
Cash and Cash Equivalents, Policy [Policy Text Block]	*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, Policy [Policy Text Block]	*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 December 31, 2017, the Partnership had sold 3.2 million common units for gross proceeds of $61.2 million and proceeds net of offering costs of $57.0 million.
Use of Estimates, Policy [Policy Text Block]	*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.
Income Tax, Policy [Policy Text Block]	*Income Tax* The Partnership is taxed as a partnership for federal and state income tax purposes. No provision for income taxes has been recorded since the liability for such taxes is that of each of the partners rather than the Partnership. The Partnership's income tax returns are subject to examination by the federal and state taxing authorities, and changes, if any, could adjust the individual income tax of the partners. The Partnership has evaluated whether any material tax position taken will more likely than not be sustained upon examination by the appropriate taxing authority and believes that all such material tax positions taken are supportable by existing laws and related interpretations.
Oil and Gas Properties Policy [Policy Text Block]	*Property and Depreciation, Depletion and Amortization* The Partnership will account for its oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. No gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties. The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.
Impairment or Disposal of Long-Lived Assets, Policy [Policy Text Block]	*Impairment* The Partnership will assess its proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, the Partnership recognizes an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management's outlook of future commodity prices. Where probable and possible reserves exist, an appropriately risk adjusted amount of these reserves is included in the impairment evaluation. The underlying commodity prices used in the determination of estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.
Asset Retirement Obligation [Policy Text Block]	*Accounting for Asset Retirement Obligations* The Partnership will have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. The removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Partnership will record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and

	abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.
Revenue Recognition, Policy [Policy Text Block]	*Revenue Recognition* Oil, natural gas and natural gas liquids revenues will be recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of 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 will not operate its oil and natural gas properties and, therefore, will receive actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well will be 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 will adjust the estimated accruals of revenue to actual production in the period actual production is determined.
Earnings Per Share, Policy [Policy Text Block]	*Net Loss per Common Unit* Basic net loss per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted net loss per 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 year ended December 31, 2017. As a result, basic and diluted outstanding common units were the same. There were no outstanding common units for the period ended December 31, 2016. The Incentive Distribution Rights (as discussed in Note 3) are not included in net loss per common unit until such time that it is probable Payout (as discussed in Note 3) would occur.
New Accounting Pronouncements, Policy [Policy Text Block]	*Recently Adopted Accounting Standards* In January 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) 2017-01, Business Combinations (Topic 805), which amends the existing accounting standards to clarify the definition of a business and assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, including interim periods within those periods, and should be applied prospectively on or after the effective date. The Partnership adopted this standard effective January 1, 2017. *Recently Issued Accounting Standards* In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), that amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. Throughout 2016, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 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. 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. The Partnership is still evaluating the impact this standard will have on its consolidated financial statements and related disclosures. 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 plans to adopt this standard in the first quarter of 2018. As of December 31, 2017, the Partnership has no outstanding hedge positions; therefore, the adoption of this standard is not expected to have a material impact on the Partnership's consolidated financial statements.

Partnership Organization (Details) - USD ($)		7 Months Ended
	Dec. 30, 2016	Jul. 25, 2017
Disclosure Text Block [Abstract]		
Limited Liability Company or Limited Partnership, Business, Formation State	Delaware	
Partners' Capital Account, Contributions	$ 1,000	
Total Amount of Unit Offering	$ 350,000,001	
Total Amount of Units Offered	17,631,579	
Minimum Unit Offering, Shares		1,315,790
Subsidiary of Limited Liability Company or Limited Partnership, Business Purpose	(i) acquire producing and non-producing oil and gas properties with development potential to be operated by third-party operators, and to enhance the value of the properties through drilling and other development activities, (ii) make distributions to the holders of the common units, (iii) engage in a liquidity transaction after five to seven years, in which all properties are sold and the sales proceeds are distributed to the partners, merge with another entity, or list the common units on a national securities exchange, and (iv) permit holders of common units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the common units primarily will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States, and to develop those properties.	

Summary of Significant Accounting Policies (Details) - USD ($)	1 Months Ended	12 Months Ended	
	Oct. 31, 2017	Dec. 31, 2017	Dec. 31, 2017
Accounting Policies [Abstract]			
Partners' Capital Account, Units, Sale of Units (in Shares)	2,631,579	3,191,231	
Proceeds from Issuance of Common Limited Partners Units		$ 61,200,000	$ 57,014,432
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units		$ 57,000,000	

Oil and Gas Investments (Details)			12 Months Ended
	Nov. 21, 2017 USD ($)	Dec. 31, 2016 USD ($)	Dec. 31, 2017 USD ($)
Oil and Gas Investments (Details) [Line Items]			
Deposits Assets, Current		$ 0	$ 8,750,000
Other Deferred Costs, Gross		0	4,884,208
Business Combination, Acquisition Related Costs		$ 0	525,000
Bakken Assets [Member]			
Oil and Gas Investments (Details) [Line Items]			
Gas and Oil Area Developed, Net	3.10%		
Productive Oil Wells, Number of Wells, Net	204		
Gas and Oil Area Undeveloped, Net	547		
Business Combination, Consideration Transferred	$ 87,500,000		
Purchase Agreement, Deposit Percentage	10.00%		
Deposits Assets, Current	$ 8,750,000		
Advisory and Consulting Services Related Party	$ 5,300,000		
Asset Disposal Fee, Related Party, Percentage	5.00%		
Other Deferred Costs, Gross			4,900,000
Business Combination, Acquisition Related Costs			$ 500,000

Capital Contribution and Partners' Equity (Details) - USD ($)			1 Months Ended	7 Months Ended	12 Months Ended	
	Dec. 31,	Dec. 30,	Oct. 31, 2017	Jul. 25, 2017	Dec. 31, 2017	Dec. 31, 2017

	2016	2016				
Partners' Capital Notes [Abstract]						
Partners' Capital Account, Contributions		$ 1,000				
Partners' Capital Account, Return of Contribution Upon Minimum Offering					$ 990	
Minimum Unit Offering, Shares (in Shares)				1,315,790		
Partners Capital Account, Units Sold, Price Per Unit (in Dollars per share)			$ 19.00	$ 19.00		
Partners' Capital Account, Units, Sale of Units (in Shares)			2,631,579			3,191,231
Proceeds from Issuance of Common Limited Partners Units					$ 57,014,432	$ 61,200,000
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units						$ 57,000,000
Partners' Capital Account, Description of Units Sold					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.	
Managing Dealer, Selling Commissions, Percentage					6.00%	
Managing Dealer, Maximum Contingent Incentive Fee on Gross Proceeds, Percentage					4.00%	
Managing Dealer, Maximum Contingent Incentive Fee on Gross Proceeds					$ 2,400,000	
Key Provisions of Operating or Partnership Agreement, Description					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.	
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)					$ 0.598357	
Distribution Made to Limited Partner, Cash Distributions Paid	$ 0				$ 1,458,398	

Line of Credit (Details) - Line of Credit [Member] - USD ($)	Jul. 25, 2017	Feb. 28, 2017
Line of Credit (Details) [Line Items]		
Line of Credit Facility, Maximum Borrowing Capacity		$ 500,000
Debt Instrument, Description of Variable Rate Basis		the line of credit of $229,000, which bore interest at a variable rate based on the London InterBank Offered Rate (LIBOR)
Repayments of Long-term Lines of Credit	$ 229,000	
Guarantor Obligations, Related Party Disclosure		Glade M. Knight, the General Partner’s Chief Executive Officer, and David S. McKenney, the General Partner’s Chief Financial Officer, had guaranteed repayment of the line of credit and did not receive any consideration in exchange for providing this guarantee.

Related Parties (Details)	12 Months Ended
	Dec. 31, 2017 USD ($)
Related Parties (Details) [Line Items]	
Related Party Transaction, Description of Transaction	Subsequent to the Partnership’s first asset purchase, the Partnership will pay quarterly an annual fee of 0.5% of the total gross equity proceeds raised by the Partnership in its offering as outlined in the prospectus.
General Partner [Member]	
Related Parties (Details) [Line Items]	
Related Party Transaction, Selling, General and Administrative Expenses from Transactions with Related Party	$ 57,000
Due to Related Parties, Current	$ 34,000

Subsequent Event (Details) - USD ($)			1 Months Ended			12 Months Ended	
	Jan. 16, 2018	Dec. 31, 2016	Feb. 23, 2018	Jan. 31, 2018	Oct. 31, 2017	Dec. 31, 2017	Dec. 31, 2017
Subsequent Event (Details) [Line Items]							
Partners' Capital Account, Units, Sale of Units (in Shares)					2,631,579		3,191,231
Proceeds from Issuance of Common Limited Partners Units						$ 57,014,432	$ 61,200,000
Distribution Made to Limited Partner, Cash Distributions Paid		$ 0				$ 1,458,398	
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)						$ 0.598357	
Subsequent Event [Member]							
Subsequent Event (Details) [Line Items]							
Distribution Made to Limited Partner, Cash Distributions Paid			$ 400,000	$ 300,000			
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)			$ 0.107397	$ 0.107397			
Subsequent Event [Member] | Best-Efforts Offering [Member]							
Subsequent Event (Details) [Line Items]							
Partners' Capital Account, Units, Sale of Units (in Shares)			200,000	200,000			
Proceeds from Issuance of Common Limited Partners Units			$ 4,000,000	$ 4,200,000			
Proceeds, Net of Selling Commissions and Marketing Expenses, from Issuance of Common Limited Partners Units			$ 3,700,000	$ 4,000,000			
Subsequent Event [Member] | Bakken Assets [Member]							
Subsequent Event (Details) [Line							

Items]							
Business Combination, Consideration Transferred	$ 87,500,000						
Related Party Transaction, Due from (to) Related Party	7,000,000						
Subsequent Event [Member] | Unsecured Debt [Member]							
Subsequent Event (Details) [Line Items]							
Debt Instrument, Face Amount	$ 25,000,000						
Debt Instrument, Maturity Date	Jan. 15, 2019						
Subsequent Event [Member] | Unsecured Debt [Member] | London Interbank Offered Rate (LIBOR) [Member]							
Subsequent Event (Details) [Line Items]							
Debt Instrument, Basis Spread on Variable Rate	2.00%						