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

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Document And Entity Information - USD ($)	12 Months Ended		
	Dec. 31, 2018	Mar. 29, 2019	Jun. 30, 2018
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		8,667,363	
Entity Public Float			$ 0
Amendment Flag	false		
Entity Central Index Key	0001696088		
Entity Current Reporting Status	Yes		
Entity Voluntary Filers	No		
Entity Filer Category	Non-accelerated Filer		
Entity Well-known Seasoned Issuer	No		
Document Period End Date	Dec. 31, 2018		
Document Fiscal Year Focus	2018		
Document Fiscal Period Focus	FY		
Entity Small Business	true		
Entity Emerging Growth Company	true		
Entity Shell Company	false		
Entity Ex Transition Period	true		

Consolidated Balance Sheets - USD ($)	Dec. 31, 2018	Dec. 31, 2017
Assets		
Cash and cash equivalents	$ 9,682,402	$ 46,859,728
Oil, natural gas and natural gas liquids revenue receivable	3,431,064	0
Derivative asset	644,786	0
Deposit for potential acquisition	0	8,750,000
Deferred acquisition costs	0	4,884,208
Total Current Assets	13,758,252	60,493,936
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization of $4,889,806 and $0,	182,078,667	0

respectively		
Derivative asset - noncurrent	234,831	0
Other assets, net	1,512,941	0
Total Assets	197,584,691	60,493,936
Liabilities		
Accounts payable and accrued expenses	11,488,175	164,786
Due to related parties	212,117	5,283,623
Total Current Liabilities	11,700,292	5,448,409
Revolving credit facility	39,500,000	0
Asset retirement obligations	383,255	0
Total Liabilities	51,583,547	5,448,409
Partners' Equity		
Limited partners' interest (7,857,359 and 3,191,231 common units issued and outstanding, respectively)	146,001,359	55,045,742
General partner's interest	(215)	(215)
Total Partners' Equity	146,001,144	55,045,527
Total Liabilities and Partners' Equity	$ 197,584,691	$ 60,493,936

Consolidated Balance Sheets (Parentheticals) - USD ($)	Dec. 31, 2018	Dec. 31, 2017
Oil and natural gas properties, successful efforts method, accumulated depreciation, depletion and amortization (in Dollars)	$ 4,889,806	$ 0
Limited partners' interest, common units issued	7,857,359	3,191,231
Limited partners' interest, common units outstanding	7,857,359	3,191,231

Consolidated Statements of Operations - USD ($)	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Revenues		
Oil	$ 23,790,225	$ 0
Natural gas	1,053,135	0
Natural gas liquids	877,676	0
Total revenue	25,721,036	0
Operating costs and expenses		
Production expenses	5,694,187	0
Production taxes	2,293,761	0
Transaction costs	0	525,000
General and administrative expenses	1,614,910	99,410
Depreciation, depletion, amortization and accretion	4,928,439	0
Total operating costs and expenses	14,531,297	624,410
Operating income (loss)	11,189,739	(624,410)
Interest income (expense), net	(1,703,327)	114,163
Gain on derivatives	879,617	0
Total other expense, net	(823,710)	114,163
Net income (loss)	$ 10,366,029	$ (510,247)
Basic and diluted net income (loss) per		

common unit (in Dollars per share)	$ 2.04	$ (0.48)
Weighted average common units outstanding - basic and diluted (in Shares)	5,091,922	1,067,941

Consolidated Statements of Partners' Equity - USD ($)	Total	Limited Partner [Member]	General Partner [Member]
Balance at Dec. 31, 2016	$ 730	$ 723	$ 7
Net proceeds from issuance of common units	57,014,432	57,014,432	
Distributions to organizational limited partner	(990)	(990)	
Distributions declared and paid to common units	(1,458,398)	(1,458,398)	
Net income (loss)	(510,247)	(510,025)	(222)
Balance at Dec. 31, 2017	55,045,527	55,045,742	(215)
Net proceeds from issuance of common units	87,634,447	87,634,447	
Distributions declared and paid to common units	(7,044,859)	(7,044,859)	
Net income (loss)	10,366,029	10,366,029	
Balance at Dec. 31, 2018	$ 146,001,144	$ 146,001,359	$ (215)

Consolidated Statements of Partners' Equity (Parentheticals) - $ / shares	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Distributions declared and paid per unit	$ 1.396164	$ 0.598357

Consolidated Statement of Cash Flows - USD ($)	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Cash flow from operating activities:		
Net income (loss)	$ 10,366,029	$ (510,247)
Adjustments to reconcile net income (loss) to cash from operating activities:		
Depreciation, depletion, amortization and accretion	4,928,439	0
Gain on mark-to-market of derivatives	(879,617)	0
Non-cash expenses, net	189,118	0
Changes in operating assets and liabilities:		
Oil, natural gas and natural gas liquids revenue receivable	(4,683,138)	0
Deferred acquisition costs	0	(4,190)
Due to related parties	(346,506)	0
Accounts payable and accrued expenses	1,256,020	560,832
Net cash flow provided by operating activities	10,830,345	46,395
Cash flow from investing activities:		
Cash paid for acquisition of oil and natural gas properties	(161,249,883)	0
Deposit for acquisition of oil and natural gas properties	0	(8,750,000)

Additions to oil and natural gas properties	(5,144,076)	0
Net cash flow used in investing activities	(166,393,959)	(8,750,000)
Cash flow from financing activities:		
Cash paid for loan costs	(1,702,059)	0
Proceeds from line of credit	0	229,000
Payments on line of credit	0	(229,000)
Proceeds from term loan	25,000,000	0
Payments on term loan	(25,000,000)	0
Proceeds from advance from member of general partner	7,000,000	0
Payments on advance from member of general partner	(7,000,000)	0
Net proceeds from revolving credit facility	39,500,000	0
Net proceeds related to issuance of common units	87,633,206	57,020,731
Distributions paid to limited partners	(7,044,859)	(1,458,398)
Net cash flow provided by financing activities	118,386,288	55,562,333
(Decrease) increase in cash and cash equivalents	(37,177,326)	46,858,728
Cash and cash equivalents, beginning of period	46,859,728	1,000
Cash and cash equivalents, end of period	9,682,402	46,859,728
Interest paid	1,557,862	1,420
Supplemental non-cash information:		
Accrued deferred costs for potential acquisition	$ 0	$ 4,880,018

Partnership Organization	12 Months Ended
	Dec. 31, 2018
Disclosure Text Block [Abstract]	
Organization, Consolidation and Presentation of Financial Statements Disclosure [Text Block]	See note below

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 offering was extended in February 2019 and in accordance with the prospectus, will expire on November 18, 2019, provided that the offering will be terminated if all of the common units are sold before then.

As of December 31, 2018, the Partnership owned an approximate 5.9% non-operated working interest in 257 currently producing wells and 37 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.

Summary of Significant Accounting Policies	12 Months Ended
	Dec. 31, 2018
Accounting Policies [Abstract]	
Significant Accounting Policies [Text Block]	**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, 2018, the Partnership had sold 7.9 million common units for gross proceeds of $154.5 million and proceeds net of offering costs of $144.6 million.

Property and Depreciation, Depletion and Amortization

The Partnership accounts 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 assesses 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.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Partnership's accounts receivable are due from purchasers of oil, natural gas and NGLs or operators of the oil and natural gas properties. Oil, natural gas and NGL sales receivables are generally unsecured. This industry concentration has the potential to impact the Partnership's overall exposure to credit risk, in that the purchasers of the Partnership's oil, natural gas and NGLs and the operators of the properties the Partnership has an interest in may be similarly affected by changes in economic, industry or other conditions. At December 31, 2018, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2018, the Partnership's oil, natural gas and NGL sales were through thirteen operators; approximately 80% of the Partnership's total revenue was generated through sales by four operators. All oil and natural gas producing activities of the Partnership are in North Dakota and represent substantially all of the business activities of the Partnership.

Accounting for Asset Retirement Obligations

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

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

The following table shows the activity for the year ended December 31, 2018 relating to the Partnership's asset retirement obligations:

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		40,644
Accretion		38,633
Balance as of December 31, 2018	$	383,255

Environmental Costs

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

Environmental liabilities are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At December 31, 2018, there were no such costs accrued.

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.

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

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

Revenue Recognition

Revenues associated with the sales of crude oil, natural gas, and natural gas liquids are recognized at the point in time when the customer obtains control of the asset. In evaluating when a customer has control of the asset, we primarily consider whether the transfer of legal title and physical delivery has occurred, whether the customer has significant risks and rewards of ownership, and whether the customer has accepted delivery and a right to payment exists. 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.

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 (loss), partners' equity or cash flows.

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.

Net Income (Loss) per Common Unit

Basic net income (loss) per common unit is computed as net income (loss) divided by the weighted average number of common units outstanding during the period. Diluted net income (loss) per common unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no common units with a dilutive effect for the years ended December 31, 2018 and 2017. As a result, basic and diluted outstanding common units were the same. The Incentive Distribution Rights (as discussed in Note 7) are not included in net income (loss) per common unit until such time that it is probable Payout (as discussed in Note 7) would occur.

Recently Adopted Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("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. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. 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. The Partnership disaggregates its revenue on the face of the consolidated statements of operations for the years ended December 31, 2018.

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 and December 2018; refer to Note 6. Risk Management for additional information.

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. The Partnership has completed its review of its existing leases and has concluded there is no material impact to the Partnership's consolidated financial statements and related disclosures.

Oil and Gas Investments	12 Months Ended
	Dec. 31, 2018
Oil and Gas Property [Abstract]	
Oil and Gas Properties [Text Block]	**Note 3. Oil and Gas Investments**

Note 3. Oil and Gas Investments

On February 1, 2018, the Partnership completed its purchase ("Acquisition No. 1") in the Bakken Assets for approximately $87.5 million, subject to customary adjustments. Acquisition No. 1 was funded using proceeds from the Partnership's best-efforts offering, proceeds from an unsecured term loan of $25.0 million and an advance from a member of the General Partner of $7.0 million. The term loan (discussed below in Note 4. Debt) was repaid in full and extinguished in December 2018. 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.

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 acquisition-related 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. In addition, 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.

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 4. 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. The Partnership also recorded an asset retirement obligation liability of approximately $0.2 million in conjunction with this acquisition.

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 $4.6 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 are being amortized over the life of the revolving credit facility described in Note 4. Debt. The deferred loan costs are recorded as Other assets, net on the Partnership's consolidated balance sheet.

Under the advisory and administration agreements (the "Agreements") with REI, REI was also entitled to a fee of 5% of the gross sales price in the event the Partnership disposed of 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 7. Capital Contribution and Partners' Equity below. On December 28, 2018, the Partnership terminated the Agreements with REI, which extinguished any potential fee upon sale of certain of the Partnership's assets as was required under the Agreements. At the time of the extinguishment, the payment of a fee was not probable and there was no value to the rights owned by REI. In connection with the termination, the General Partner issued 500 of its Class B Units to each of Pope Energy Investors, LP and CFK Energy, LLC. The General Partner received $250 from each of Pope Energy Investors, LP and CFK Energy, LLC for this transaction. The General Partner Class B Units are non-voting and participate in 50% of any distributions by the General Partner from proceeds of its Incentive Distribution Rights, after Payout and the Dealer Manager Incentive Fees as described in Note 7. Capital Contribution and Partners' Equity 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. In addition, CFK Energy, LLC and Pope Energy Investors, LP are owned by entities controlled by Messrs. Keating and Mallick, respectively. See Note 8. Related Parties below for additional information.

The following unaudited pro forma financial information for the years December 31, 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.

	Year Ended December 31, 2018 (Unaudited)	Year Ended December 31, 2017 (Unaudited)
Revenues	$ 43,067,089	$ 29,484,426
Net income	$ 18,604,782	$ 9,864,799

As of December 31, 2018, the Partnership's ownership of the Bakken Assets consisted of an approximate 5.9% non-operated working interest in 257 currently producing wells and 37 wells in various stages of the drilling and completion process.

From September 1, 2017, the effective date of Acquisition No. 1, to December 31, 2018, the Partnership has participated in the drilling of 93 wells, of which 56 have been completed and 37 wells are in various stages of completion at December 31, 2018. From February 1, 2018, the closing date of Acquisition No. 1, to December 31, 2018, the Partnership incurred approximately $15.4 million in capital drilling and completion costs. As of December 31, 2018, the Partnership had approximately $10.3 million in outstanding capital expenditures, which are included in Accounts payable and accrued liabilities on the Partnership's consolidated balance sheet. The Partnership anticipates approximately $13 million of capital expenditures to be incurred in 2019 to complete the 37 wells in various stages of completion at December 31, 2018.

Non-consent wells

Pursuant to the terms of the American Association of Professional Landmen Model Form Operating Agreement or North Dakota statute, each of which may govern operations between an operator and a non-operated working interest owner ("interest owner"), like the Partnership, an operator must notify an interest owner of its intention to drill a new well through submittal of a formal well proposal. The interest owner has the option to elect to participate in the drilling, completion and operating of the well and pay its proportionate share of all costs, or the interest owner may elect to non-consent the proposed well under the terms of the operating agreement or statute and bear no cost. If the interest owner elects to non-consent the proposed well, the interest owner is not obligated to pay any portion of the drilling, completion and operating expenses; however, the interest owner is then subject to a non-consent penalty under the terms of the operating agreement or North Dakota statute.

Through its 2018 acquisitions, the Partnership acquired 59 wells designated as non-consent wells, whereby a previous interest owner did not consent to participate in the drilling and completion of those wells. As a result, the Partnership is currently subject to non-consent penalties ranging from 200%-400%, meaning in general terms, the Partnership will remain in non-consent status and will not receive any revenue from these wells until the wells have satisfied the contractual or statutory penalties of 2-4 times payout of the expenses related to drilling, completion and operating the well. The Partnership may receive revenue or be responsible for operating and/or abandonment costs from all or a portion of these wells if the wells generate enough revenue to exceed the non-consent penalties described above.

Debt	12 Months Ended
	Dec. 31, 2018
Debt Disclosure [Abstract]	
Debt Disclosure [Text Block]	**Note 4. Debt**

Note 4. Debt

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 was paid in full and extinguished in December 2018. Interest was payable monthly, and the Term Loan bore interest at a variable rate based on the London Inter-Bank Offered Rate (LIBOR) plus a margin of 2.00%. The Term Loan proceeds were used in closing on Acquisition No. 1, as described above. Glade M. Knight and David S. McKenney, the General Partner's Chief Executive Officer and Chief Financial Officer, respectively, had guaranteed repayment of the Term Loan and did 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").

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. At December 31, 2018, the Lender commitment was $40.0 million and the interest rate for the Credit Facility was approximately 6.25%. At December 31, 2018, the outstanding balance on the Credit Facility was $39.5 million. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time.

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 December 31, 2018.

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 and extinguished 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.

As of December 31, 2018 and 2017, the Partnership's outstanding debt balance was $39.5 million and $0, respectively. The outstanding balance at December 31, 2018 of $39.5 million approximates its fair market value. The Partnership estimated the fair value of its note payable by discounting the future cash flows of the instrument at estimated market rates consistent with the maturity of a debt obligation with similar credit terms and credit characteristics, which are Level 3 inputs under the fair value hierarchy. Market rates take into consideration general market conditions and maturity.

Fair Value of Financial Instruments	12 Months Ended Dec. 31, 2018
Fair Value Disclosures [Abstract]	
Fair Value Disclosures [Text Block]	**Note 5. Fair Value of Financial Instruments**

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

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

The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and the consideration of factors specific to the asset or liability. The Partnership's policy is to recognize transfers in or out of a fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Partnership has consistently applied the valuation techniques discussed above for all periods presented. During the years ended December 31, 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 December 31, 2018.

	Fair Value Measurements at December 31, 2018		
	Quoted Prices in Active Markets		**Significant**

	for Identical Assets (Level 1)		Significant Other Observable Inputs (Level 2)		Unobservable Inputs (Level 3)	
Commodity derivatives - current assets	$	-	$	644,786	$	-
Commodity derivatives - current liabilities		-		-		-
Commodity derivatives - noncurrent assets		-		234,831		-
Commodity derivatives - noncurrent liabilities		-		-		-
Total	$	-	$	879,617	$	-

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 as Derivative asset at December 31, 2018. See additional detail in Note 6. Risk Management.

Fair Value of Other Financial Instruments

The carrying value of the Partnership's cash and cash equivalents, oil, natural gas and natural gas liquids revenue receivable, accounts payable and accrued expenses 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 4. Debt for the fair value discussion on the Partnership's debt.

Risk Management	12 Months Ended
	Dec. 31, 2018
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Derivative Instruments and Hedging Activities Disclosure [Text Block]	**Note 6. Risk Management**

Note 6. 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. Under the Credit Facility, the Partnership is required to maintain a risk management program, covering at least 50% of the Partnership's total estimated monthly production of oil and natural gas through the maturity date of August 31, 2021. Therefore, in September and December 2018, the Partnership entered into derivative contracts through June 2020 to manage the commodity price risk on a portion of the Partnership's anticipated future oil and gas 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 December 31, 2018, the Partnership's costless collar derivative instrument was in a net gain position; therefore, an asset of approximately $0.9 million, which approximates its fair value, has been recognized as Derivative asset (current and noncurrent) on the Partnership's consolidated balance sheet.

The Partnership's derivative contracts are costless collars, which are used to establish floor and ceiling prices on future anticipated oil and gas production. The Partnership did not pay or receive a premium related to the costless collar agreements. The contracts are settled monthly and there were no settlement payables or receivables at December 31, 2018. The Partnership's September 2018 and December 2018 derivative contracts had been settled at December 31, 2018 at no cost or benefit to the Partnership, as the contract price on the date of settlement was within the established floor and ceiling prices. The follow table reflects the open costless collar instrument as of December 31, 2018.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)		Fair Value of Asset / (Liability) at December 31, 2018
01/01/19 - 12/31/19	NYMEX	266,000	45.00 / 60.35	$	644,786
01/01/20 - 06/30/20	NYMEX	107,000	45.00 / 61.20		234,831
		373,000		$	879,617

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 gain of approximately $0.9 million for the year ended December 31, 2018, which was recorded on the consolidated statements of operations as Gain on derivatives.

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 5. Fair Value of Financial Instruments.

The Partnership's outstanding derivative instruments are 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.

Capital Contribution and Partners' Equity	12 Months Ended Dec. 31, 2018
Partners' Capital Notes [Abstract]	
Partners' Capital Notes Disclosure [Text Block]	(see below)

Note 7. Capital Contribution and Partners' Equity

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

As of 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, 2018, the Partnership had completed the sale of 7.9 common units for gross proceeds of approximately $154.5 million and proceeds net of offering costs of approximately $144.6 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 offering will end on the earlier of all common units registered being sold, or November 18, 2019.

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, 2018, the Dealer Manager Incentive Fees are approximately $6.2 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, 2018, the Partnership paid distributions of $1.396164 per common unit, or $7.0 million. For the year ended December 31, 2017, the Partnership paid distributions of $0.598357 per common unit, or $1.5 million.

Related Parties	12 Months Ended
	Dec. 31, 2018
Related Party Transactions [Abstract]	
Related Party Transactions Disclosure [Text Block]	**Note 8. Related Parties** The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to any existing related party transactions, as well as any new significant related party transactions. 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 December 31, 2018, the management fee paid to the General Partner for the year ended December 31, 2018 was approximately $537,000. The management fee paid to the General Partner is 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 years ended December 31, 2018 and 2017, approximately $402,000 and $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, 2018, approximately $135,000 was due to a member of the General Partner and is included in Due to related parties in the consolidated balance sheets. As discussed in Note 3. Oil and Gas Investments, 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. As discussed in Note 4. Debt, the Chief Executive Officer and Chief Financial Officer of the Partnership's General Partner had guaranteed repayment of the Term Loan as well as the 2017 unsecured line of credit, of which both facilities were agreements with Bank of America. Neither the Chief Executive Officer nor the Chief Financial Officer received any consideration in exchange for providing the guarantee on either loan. 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 year ended December 31, 2018, approximately $252,000 of expenses subject to the cost sharing agreement were incurred by the Partnership and have been or will be reimbursed to Energy 11. At December 31, 2018, approximately $77,000 was due from the Partnership to Energy 11 and is included in Due to related parties in the consolidated balance sheets.

As discussed in Note 3. Oil and Gas Investments, in November 2017 and June 2018, the Partnership engaged REI to perform advisory and consulting services, including supporting the Partnership through closing, financing and post-closing on Acquisitions No. 1 and No. 2. REI is owned by entities that are controlled by Messrs. Keating and Mallick and has engaged Cliff Merritt, President of Energy 11 GP, LLC, to support its operations. With the fees received from the Partnership for advisory and consulting services, REI paid certain personnel utilized by Energy 11 and the Partnership, including Mr. Merritt, an aggregate total of $500,000. Under the advisory and administration agreements (the "Agreements") with REI, REI was 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 were available after Payout to the holders of the Partnership's common units, as defined in Note 7. Capital Contribution and Partners' Equity above. On December 28, 2018, the Partnership terminated the Agreements with REI, which extinguished any potential fee upon sale of certain of the Partnership's assets as was required under the Agreements. At the time of the extinguishment, the payment of a fee was not probable and there was no value to the rights owned by REI. In connection with the termination, the General Partner issued 500 of its Class B Units each to entities owned and controlled by Messrs. Keating and Mallick in exchange for $500 total. The General Partner Class B Units are non-voting and participate in 50% of any distributions by the General Partner from proceeds of its Incentive Distribution Rights, after Payout and the Dealer Manager Incentive Fees as described in Note 7. Capital Contribution and Partners' Equity above.

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)	12 Months Ended
	Dec. 31, 2018
Oil and Gas Exploration and Production Industries Disclosures [Abstract]	
Oil and Gas Exploration and Production Industries Disclosures [Text Block]	(see below)

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

Aggregate Capitalized Costs and Costs Incurred

The aggregate amount of capitalized costs of oil, natural gas and NGL properties, including development, and related accumulated depreciation, depletion and amortization as of December 31, 2018 is as follows:

		2018
Producing properties acquired	$	103,025,742
Non-producing acquired		68,481,176
Development		15,461,555
		186,968,473
Accumulated depreciation, depletion and amortization		(4,889,806)
Net capitalized costs	$	182,078,667

Estimated Quantities of Proved Oil, NGL and Natural Gas Reserves

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

Proved oil and natural gas reserves are those quantities of oil, natural gas and NGLs which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of Pinnacle Energy of Oklahoma City, OK, prepared estimates of the Partnership's oil, natural gas and NGL reserves as of December 31, 2018.

The Partnership's net proved oil, NGL and natural gas reserves, all of which are located in the contiguous United States, as of December 31, 2018 have been estimated by the Partnership's independent consulting petroleum engineering firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with SEC rules and regulations along with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

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

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

	Proved Reserves			
	Oil (Bbls)	**Natural Gas (Mcf)**	**NGLs (Bbls)**	**Total (BOE)**
January 1, 2018	-	-	-	-
Acquisition No. 1 (1)	9,717,859	4,957,715	712,913	11,257,058
Acquisition No. 2 (2)	10,298,392	4,779,497	696,600	11,791,575
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (3)	653,770	545,023	124,901	869,507
Production (February 1, 2018 to December 31, 2018)	(405,581)	(319,445)	(42,329)	(501,150)
December 31, 2018	20,264,440	9,962,790	1,492,085	23,416,990

(1) The Partnership acquired 11,257 MBOE of reserves attributable to producing developed wells and PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

(2) The Partnership acquired 11,792 MBOE of reserves attributable to producing developed wells and PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

(3) Revisions to previous estimates increased proved reserves by a net amount of 870 MBOE. These revisions result from 1,248 MBOE of upward adjustments attributable to changes in the future drill schedule and 7 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to the drill schedules and oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2, which were partially offset by 385 MBOE of downward adjustments related to well performance post acquisition-closing dates.

In accordance with SEC Regulation S-X, Rule 4-10, as amended, the Partnership uses the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period.

The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2018 were $65.56 per barrel of oil and $3.10 per MMcf of natural gas, before price differentials. Including the effect of average price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2018 were $59.56 per barrel of oil, $2.43 per MMcf of natural gas and $20.25 per barrel of NGL.

	Oil (Bbls)	**Natural Gas (Mcf)**	**NGLs (Bbls)**	**Total (BOE)**
Proved developed reserves:				
December 31, 2018	6,982,216	4,126,780	686,765	8,356,778
Proved undeveloped reserves:				
December 31, 2018	13,282,224	5,836,010	805,320	15,060,212

The following details the changes in proved undeveloped reserves for 2018 (in BOE):

	BOE
Proved undeveloped reserves, beginning	-
Proved undeveloped reserves acquired in Acquisition No. 1 (1)	8,427,708
Proved undeveloped reserves acquired in Acquisition No. 2 (2)	7,279,846
Revisions of previous estimates (3)	1,252,630
Conversion to proved developed reserves (4)	(1,899,972)
Proved undeveloped reserves, December 31, 2018	15,060,212

(1) The Partnership acquired 8,428 MBOE attributable to PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

(2) The Partnership acquired 7,280 MBOE attributable to PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

(3) Revisions to previous estimates, from the respective closing dates for Acquisitions No. 1 and No. 2, increased PUDs by a net amount of 1,253 MBOE. These revisions result from 1,249 MBOE of upward adjustments attributable to changes in the future drill schedule and 4 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2. There were no adjustments related to well performance.

(4) Since the Partnership completed its first acquisition, 56 wells have either been completed or are in-process by the Partnership's operators. This development has led to 1,900 MBOE of PUDs being converted to proved developed reserves from February 1, 2018 to December 31, 2018.

The Partnership anticipates all current PUD locations will be drilled and converted to PDP within five years of the date they were added. PUD locations and associated reserves which are no longer projected to be drilled within five years from the date they were first booked as proved undeveloped reserves have been removed as revisions at the time that determination was made.

Standardized Measure of Discounted Future Net Cash Flows

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

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

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

	2018
	(in thousands)

Future cash inflows	$	1,256,302
Future production costs		(342,615)
Future development costs		(102,210)
Future net cash flows		811,477
10% annual discount		(440,982)
Standardized measure of discounted future net cash flows	$	370,495

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

	2018 (in thousands)	
Standardized measure at beginning of period	$	-
Changes resulting from:		
Acquisition of reserves		273,568
Sales of oil, natural gas and NGLs, net of production costs		(17,733)
Net changes in prices and production costs		71,883
Development costs incurred during the period		15,462
Revisions to previous estimates		11,491
Accretion of discount		15,174
Change in estimated future development costs		650
Standardized measure of discounted future net cash flows	$	370,495

Quarterly Financial Data (Unaudited)	12 Months Ended Dec. 31, 2018
Quarterly Financial Information Disclosure [Abstract]	
Quarterly Financial Information [Text Block]	**Note 10. Quarterly Financial Data (Unaudited)**

Note 10. Quarterly Financial Data (Unaudited)

The following is a summary of quarterly results of operations for the years ended December 31, 2018 and 2017. Net income (loss) per common unit is non-additive in comparison to net income (loss) per common unit for each year due to the timing and size of the Partnership's common unit issuances.

	2018 (1) First Quarter	2018 (1) Second Quarter	2018 (1) Third Quarter	2018 (1) Fourth Quarter
Total revenue	$ 3,497,079	$ 7,531,096	$ 5,503,706	$ 9,189,155
Net income	$ 1,288,325	$ 3,400,535	$ 2,087,725	$ 3,589,444
Basic and diluted net income per common share	$ 0.38	$ 0.82	$ 0.37	$ 0.51

	2017 First Quarter	2017 Second Quarter	2017 Third Quarter	2017 Fourth Quarter
Total revenue	$ -	$ -	$ -	$ -
Net income (loss)	$ (6,535)	$ (15,675)	$ 12,524	$ (500,561)
Basic and diluted net income (loss) per common share	$ -	$ -	$ 0.01	$ (0.18)

(1) The Partnership did not acquire its first operating asset until February 1, 2018.

Subsequent Events	12 Months Ended Dec. 31, 2018
Subsequent Events [Abstract]	
Subsequent Events [Text Block]	**Note 11. Subsequent Events**

In January 2019, the Partnership closed on the issuance of approximately 0.3 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $5.1 million and proceeds net of selling and marketing costs of approximately $4.8 million.

In January 2019, the Partnership declared and paid $0.8 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In February 2019, 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 $4.4 million and proceeds net of selling and marketing costs of approximately $4.2 million.

In February 2019, the Partnership declared and paid $0.9 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

In March 2019, the Partnership entered into additional costless collar derivative contracts to hedge a portion of the Partnership's future oil and natural gas production for the period from April 2019 to September 2020. The contracts cover approximately 108,000 BOE of oil and natural gas production for the stated period. The Partnership did not pay or receive a premium related to the costless collar agreements.

In March 2019, the Partnership closed on the issuance of approximately 0.3 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $6.9 million and proceeds net of selling and marketing costs of approximately $6.5 million.

In March 2019, the Partnership declared and paid $1.1 million, or $0.134247 per outstanding common unit, in distributions to its holders of common units.

Accounting Policies, by Policy (Policies)	12 Months Ended Dec. 31, 2018
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, 2018, the Partnership had sold 7.9 million common units for gross proceeds of $154.5 million and proceeds net of offering costs of $144.6 million.
Oil and Gas Properties Policy [Policy Text Block]	*Property and Depreciation, Depletion and Amortization* The Partnership accounts 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 assesses 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.
Concentration Risk, Credit Risk, Policy [Policy Text Block]	*Accounts Receivable and Concentration of Credit Risk* Substantially all of the Partnership’s accounts receivable are due from purchasers of oil, natural gas and NGLs or operators of the oil and natural gas properties. Oil, natural gas and NGL sales receivables are generally unsecured. This industry concentration has the potential to impact the Partnership’s overall exposure to credit risk, in that the purchasers of the Partnership’s oil, natural gas and NGLs and the operators of the properties the Partnership has an interest in may be similarly affected by changes in economic, industry or other conditions. At December 31, 2018, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2018, the Partnership’s oil, natural gas and NGL sales were through thirteen operators; approximately 80% of the Partnership’s total revenue was generated through sales by four operators. All oil and natural gas producing activities of the Partnership are in North Dakota and represent substantially all of the business activities of the Partnership.
Asset Retirement Obligation [Policy Text Block]	*Accounting for Asset Retirement Obligations* The Partnership has 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 records an asset retirement obligation (“ARO”) and capitalizes the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

The following table shows the activity for the year ended December 31, 2018 relating to the Partnership's asset retirement obligations:

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		40,644
Accretion		38,633
Balance as of December 31, 2018	$	383,255

Environmental Costs, Policy [Policy Text Block]	*Environmental Costs* As the Partnership is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays. The Partnership does not believe the existence of current environmental laws or interpretations thereof will materially hinder or adversely affect the Partnership's business operations; however, there can be no assurances of future effects on the Partnership of new laws or interpretations thereof. Since the Partnership does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with the Partnership being responsible for its proportionate share of the costs involved. Environmental liabilities are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At December 31, 2018, there were no such costs accrued.
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. Of these estimates and assumptions, management considers the estimation of oil, natural gas and NGL reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as depreciation, depletion and amortization ("DD&A") and impairment calculations. On an annual basis, the Partnership's independent consulting petroleum engineer, with assistance from the Partnership, prepares estimates of oil, natural gas and NGL reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. For DD&A purposes, and as required by the guidelines and definitions established by the Securities and Exchange Commission ("SEC"), the reserve estimates were based on average individual product prices during the 12-month period prior to December 31, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period excluding escalations based upon future conditions. For impairment purposes, projected NYMEX forward strip prices for oil, natural gas and NGL as estimated by management are used. Oil, natural gas and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future oil, natural gas and NGL pricing assumptions are used by management to prepare estimates of oil, natural gas and NGL reserves used in formulating management's overall operating decisions. The Partnership does not operate its oil and natural gas properties and, therefore, receives actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well are used to estimate the accrual of revenue on these wells. The oil, natural gas and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, natural gas and NGLs. These variables could lead to an over or under accrual of oil, natural gas and NGL sales at the end of any particular quarter. However, the Partnership adjusts the estimated accruals of revenue to actual production in the period actual production is determined.
Revenue Recognition, Policy [Policy Text Block]	*Revenue Recognition* Revenues associated with the sales of crude oil, natural gas, and natural gas liquids are recognized at the point in time when the customer obtains control of the asset. In evaluating when a customer has control of the asset, we primarily consider whether the transfer of legal title and physical delivery has occurred, whether the customer has significant risks and rewards of ownership, and whether the customer has accepted delivery and a right to payment exists. 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.
Reclassification, Policy [Policy Text	*Reclassifications*

Block]	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 (loss), partners' equity or cash flows.
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.
Earnings Per Share, Policy [Policy Text Block]	*Net Income (Loss) per Common Unit* Basic net income (loss) per common unit is computed as net income (loss) divided by the weighted average number of common units outstanding during the period. Diluted net income (loss) per common unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no common units with a dilutive effect for the years ended December 31, 2018 and 2017. As a result, basic and diluted outstanding common units were the same. The Incentive Distribution Rights (as discussed in Note 7) are not included in net income (loss) per common unit until such time that it is probable Payout (as discussed in Note 7) would occur.
New Accounting Pronouncements, Policy [Policy Text Block]	*Recently Adopted Accounting Standards* In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("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. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. 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. The Partnership disaggregates its revenue on the face of the consolidated statements of operations for the years ended December 31, 2018. 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 and December 2018; refer to Note 6. Risk Management for additional information. *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. The Partnership has completed its review of its existing leases and has concluded there is no material impact to the Partnership's consolidated financial statements and related disclosures.

Summary of Significant Accounting Policies (Tables)	**12 Months Ended**
	Dec. 31, 2018
Accounting Policies [Abstract]	
Schedule of Asset Retirement Obligations [Table Text Block]	The following table shows the activity for the year ended December 31, 2018 relating to the Partnership's asset retirement obligations:

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		40,644
Accretion		38,633

Balance as of December 31, 2018	$ 383,255

Oil and Gas Investments (Tables)	12 Months Ended Dec. 31, 2018
Oil and Gas Property [Abstract]	
Business Acquisition, Pro Forma Information [Table Text Block]	The following unaudited pro forma financial information for the years December 31, 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.

	Year Ended December 31, 2018 (Unaudited)	Year Ended December 31, 2017 (Unaudited)
Revenues	$ 43,067,089	$ 29,484,426
Net income	$ 18,604,782	$ 9,864,799

Fair Value of Financial Instruments (Tables)	12 Months Ended Dec. 31, 2018
Fair Value Disclosures [Abstract]	
Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Table Text Block]	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 December 31, 2018.

	Fair Value Measurements at December 31, 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	$ -	$ 644,786	$ -
Commodity derivatives - current liabilities	-	-	-
Commodity derivatives - noncurrent assets	-	234,831	-
Commodity derivatives - noncurrent liabilities	-	-	-
Total	$ -	$ 879,617	$ -

Risk Management (Tables)	12 Months Ended Dec. 31, 2018
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Schedule of Derivative Instruments [Table Text Block]	The follow table reflects the open costless collar instrument as of December 31, 2018.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)	Fair Value of Asset / (Liability) at December 31, 2018
01/01/19 - 12/31/19	NYMEX	266,000	45.00 / 60.35	$ 644,786
01/01/20 - 06/30/20	NYMEX	107,000	45.00 / 61.20	234,831
		373,000		$ 879,617

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Tables)	12 Months Ended
	Dec. 31, 2018
Oil and Gas Exploration and Production Industries Disclosures [Abstract]	
Capitalized Costs Relating to Oil and Gas Producing Activities Disclosure [Table Text Block]	The aggregate amount of capitalized costs of oil, natural gas and NGL properties, including development, and related accumulated depreciation, depletion and amortization as of December 31, 2018 is as follows:

	2018
Producing properties acquired	$ 103,025,742
Non-producing acquired	68,481,176
Development	15,461,555
	186,968,473
Accumulated depreciation, depletion and amortization	(4,889,806)
Net capitalized costs	$ 182,078,667

Schedule of Proved Developed and Undeveloped Oil and Gas Reserve Quantities [Table Text Block]

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

	Proved Reserves			
	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
January 1, 2018	-	-	-	-
Acquisition No. 1 (1)	9,717,859	4,957,715	712,913	11,257,058
Acquisition No. 2 (2)	10,298,392	4,779,497	696,600	11,791,575
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (3)	653,770	545,023	124,901	869,507
Production (February 1, 2018 to December 31, 2018)	(405,581)	(319,445)	(42,329)	(501,150)
December 31, 2018	20,264,440	9,962,790	1,492,085	23,416,990

	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
Proved developed reserves:				
December 31, 2018	6,982,216	4,126,780	686,765	8,356,778
Proved undeveloped reserves:				
December 31, 2018	13,282,224	5,836,010	805,320	15,060,212

	BOE
Proved undeveloped reserves, beginning	-
Proved undeveloped reserves acquired in Acquisition No. 1 (1)	8,427,708
Proved undeveloped reserves acquired in Acquisition No. 2 (2)	7,279,846
Revisions of previous estimates (3)	1,252,630
Conversion to proved developed reserves (4)	(1,899,972)
Proved undeveloped reserves, December 31, 2018	15,060,212

(1) The Partnership acquired 11,257 MBOE of reserves attributable to producing developed wells and PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

(2) The Partnership acquired 11,792 MBOE of reserves attributable to producing developed wells and PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

(3) Revisions to previous estimates increased proved reserves by a net amount of 870 MBOE. These revisions result from 1,248 MBOE of upward adjustments attributable to changes in the future drill schedule and 7 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to the drill schedules and oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2, which were partially offset by 385 MBOE of downward adjustments related to well performance post acquisition-closing dates.

(1) The Partnership acquired 8,428 MBOE attributable to PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

(2) The Partnership acquired 7,280 MBOE attributable to PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

(3) Revisions to previous estimates, from the respective closing dates for Acquisitions No. 1 and No. 2, increased PUDs by a net amount of 1,253 MBOE. These revisions result from 1,249 MBOE of upward adjustments attributable to changes in the future drill schedule and 4

	MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2. There were no adjustments related to well performance. (4) Since the Partnership completed its first acquisition, 56 wells have either been completed or are in-process by the Partnership's operators. This development has led to 1,900 MBOE of PUDs being converted to proved developed reserves from February 1, 2018 to December 31, 2018.
Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Table Text Block]	The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect the Partnership's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates affect the valuation process.

	2018
	(in thousands)
Future cash inflows	$ 1,256,302
Future production costs	(342,615)
Future development costs	(102,210)
Future net cash flows	811,477
10% annual discount	(440,982)
Standardized measure of discounted future net cash flows	$ 370,495

Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows [Table Text Block]

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

	2018
	(in thousands)
Standardized measure at beginning of period	$ -
Changes resulting from:	
Acquisition of reserves	273,568
Sales of oil, natural gas and NGLs, net of production costs	(17,733)
Net changes in prices and production costs	71,883
Development costs incurred during the period	15,462
Revisions to previous estimates	11,491
Accretion of discount	15,174
Change in estimated future development costs	650
Standardized measure of discounted future net cash flows	$ 370,495

Quarterly Financial Data (Unaudited) (Tables)	**12 Months Ended**
	Dec. 31, 2018
Quarterly Financial Information Disclosure [Abstract]	
Quarterly Financial Information [Table Text Block]	The following is a summary of quarterly results of operations for the years ended December 31, 2018 and 2017. Net income (loss) per common unit is non-additive in comparison to net income (loss) per common unit for each year due to the timing and size of the Partnership's common unit issuances.

	2018 (1)			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Total revenue	$ 3,497,079	$ 7,531,096	$ 5,503,706	$ 9,189,155
Net income	$ 1,288,325	$ 3,400,535	$ 2,087,725	$ 3,589,444
Basic and diluted net income per common share	$ 0.38	$ 0.82	$ 0.37	$ 0.51
	2017			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Total revenue	$ -	$ -	$ -	$ -
Net income (loss)	$ (6,535)	$ (15,675)	$ 12,524	$ (500,561)
Basic and diluted net income (loss) per common share	$ -	$ -	$ 0.01	$ (0.18)

(1) The Partnership did not acquire its first operating asset until February 1, 2018.

Partnership Organization (Details)		7 Months Ended	12 Months Ended
	Dec. 30, 2016 USD ($) shares	Jul. 25, 2017 shares	Dec. 31, 2018
Partnership Organization (Details) [Line Items]			
Limited Liability Company or Limited Partnership, Business, Formation State	Delaware		
Partners' Capital Account, Contributions (in Dollars) | $	$ 1,000		
Total Amount of Unit Offering (in Dollars) | $	$ 350,000,001		
Total Amount of Units Offered (in Shares) | shares	17,631,579		
Minimum Unit Offering, Shares (in Shares) | shares		1,315,790	
Bakken Assets [Member]			
Partnership Organization (Details) [Line Items]			
Gas and Oil Area Developed, Net			5.90%
Productive Oil Wells, Number of Wells, Net			257
Wells in Process of Drilling			37
Number of Operators			14

Summary of Significant Accounting Policies (Details)	1 Months Ended	12 Months Ended		24 Months Ended
	Oct. 31, 2017 shares	Dec. 31, 2018 USD ($)	Dec. 31, 2017 USD ($)	Dec. 31, 2018 USD ($) shares
Summary of Significant Accounting Policies (Details) [Line Items]				
Partners' Capital Account, Units, Sale of Units (in Shares) | shares	2,631,579			7,900,000
Proceeds from Issuance of Common Limited Partners Units (in Dollars)		$ 87,634,447	$ 57,014,432	$ 154,500,000
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units (in Dollars)				$ 144,600,000
Sales Revenue, Net [Member]				
Summary of Significant Accounting Policies (Details) [Line Items]				
Number of Operators		13		
Four Operators [Member] | Customer Concentration Risk [Member] | Sales Revenue, Net [Member]				
Summary of Significant Accounting Policies (Details) [Line Items]				
Number of Operators		4		
Concentration Risk, Percentage		80.00%		

Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations	12 Months Ended
	Dec. 31, 2018 USD ($)
Summary of Significant Accounting	

Policies (Details) - Schedule of Asset Retirement Obligations [Line Items]	
Balance	$ 0
Well additions	40,644
Accretion	38,633
Balance	383,255
Acquisition No. 1 [Member]	
Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations [Line Items]	
Well additions	133,155
Acquisition No. 2 [Member]	
Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations [Line Items]	
Well additions	$ 170,823

Oil and Gas Investments (Details)				3 Months Ended		8 Months Ended	12 Months Ended		16 Months Ended
	Dec. 28, 2018 USD ($) shares	Aug. 31, 2018 USD ($)	Feb. 01, 2018 USD ($)	Sep. 30, 2018 USD ($)	Mar. 31, 2018 USD ($)	Sep. 30, 2018 USD ($)	Dec. 31, 2018 USD ($)	Dec. 31, 2017 USD ($)	Dec. 31, 2018 USD ($)
Oil and Gas Investments (Details) [Line Items]									
Proceeds from Issuance of Unsecured Debt							$ 25,000,000	$ 0	
Proceeds from Related Party Debt							7,000,000	0	
Asset Retirement Obligation, Liabilities Incurred							40,644		
Proceeds from Lines of Credit							$ 0	$ 229,000	
Development Wells Drilled, Net Productive							56		
Non-consent well description							Pursuant to the terms of the American Association of Professional Landmen Model Form Operating Agreement or North Dakota statute, each of which may govern operations between an operator and a non-operated working interest owner (“interest owner”), like the Partnership, an operator must notify an interest owner of its intention to drill a new well through submittal of a		

							formal well proposal. The interest owner has the option to elect to participate in the drilling, completion and operating of the well and pay its proportionate share of all costs, or the interest owner may elect to non-consent the proposed well under the terms of the operating agreement or statute and bear no cost. If the interest owner elects to non-consent the proposed well, the interest owner is not obligated to pay any portion of the drilling, completion and operating expenses; however, the interest owner is then subject to a non-consent penalty under the terms of the operating agreement or North Dakota statute.Through its 2018 acquisitions, the Partnership acquired 59 wells designated as non-consent wells, whereby a previous interest owner did not consent to participate in the drilling and completion of those wells. As a result, the Partnership is currently subject to non-consent penalties ranging from 200%-400%, meaning in general terms,		

							the Partnership will remain in non-consent status and will not receive any revenue from these wells until the wells have satisfied the contractual or statutory penalties of 2-4 times payout of the expenses related to drilling, completion and operating the well. The Partnership may receive revenue or be responsible for operating and/or abandonment costs from all or a portion of these wells if the wells generate enough revenue to exceed the non-consent penalties described above.		
Number of Wells Designated as Non-Consent Wells							59		
Acquisition No. 1 [Member]									
Oil and Gas Investments (Details) [Line Items]									
Costs Incurred, Development Costs							$ 10,300,000		
Asset Retirement Obligation, Liabilities Incurred							133,155		
Capital Expenditures Drilling and Completion of Wells							13,000,000		
Acquisition No. 2 [Member]									
Oil and Gas Investments (Details) [Line Items]									
Asset Retirement Obligation, Liabilities Incurred							$ 170,823		
Capital Unit, Class B [Member]									
Oil and Gas Investments (Details) [Line Items]									
In connection with termination of agreements with REI, the General Partner issued 500 of its non-voting Class B Units to entities controlled by related parties (in Shares) | shares	500								
Payment made by entities controlled by related parties to General Partner for non-voting Class B Units	$ 250								
In connection with termination of agreements with REI, entities controlled by related parties have acquired a non-	50.00%								

voting interest in the General Partner									
Minimum [Member]									
Oil and Gas Investments (Details) [Line Items]									
Non-consent penalty range							200.00%		
Maximum [Member]									
Oil and Gas Investments (Details) [Line Items]									
Non-consent penalty range							400.00%		
Bakken Assets [Member]									
Oil and Gas Investments (Details) [Line Items]									
Costs Incurred, Development Costs				$ 2,700,000					
Deferred Costs							$ 1,400,000		$ 1,400,000
Gas and Oil Area Developed, Net							5.90%		
Productive Oil Wells, Number of Wells, Net							257		257
Wells in Process of Drilling							37		37
Bakken Assets [Member] | Affiliated Entity [Member]									
Oil and Gas Investments (Details) [Line Items]									
Advisory and Consulting Services Related Party					$ 5,300,000				
Asset Disposal Fee, Related Party, Percentage							5.00%		
Bakken Assets [Member] | Acquisition No. 1 [Member]									
Oil and Gas Investments (Details) [Line Items]									
Business Combination, Consideration Transferred			$ 87,500,000						
Proceeds from Issuance of Unsecured Debt			25,000,000						
Proceeds from Related Party Debt			7,000,000						
Costs Incurred, Development Costs			5,000,000			$ 15,400,000			
Asset Retirement Obligation, Liabilities Incurred					100,000				
Non-cash Transaction Increase in Accounts Receivable Settlement of Pre-close Activity			$ 2,100,000						
Wells in Process of Drilling							37		37
Wells Drilled									93
Development Wells Drilled, Net Productive									56
Bakken Assets [Member] | Acquisition No. 1 [Member] | Affiliated Entity [Member]									
Oil and Gas Investments (Details) [Line Items]									
Acquisition Costs, Period Cost					$ 4,700,000				
Bakken Assets [Member] | Acquisition No. 2 [Member]									
Oil and Gas Investments (Details) [Line Items]									

Business Combination, Consideration Transferred		$ 82,500,000							
Asset Retirement Obligation, Liabilities Incurred		200,000							
Proceeds from Lines of Credit		60,000,000							
Acquisition Costs, Period Cost		$ 2,900,000							
Business Combination, Provisional Information, Initial Accounting Incomplete, Adjustment, Financial Assets							$ 4,600,000		
Bakken Assets [Member] | Acquisition No. 2 [Member] | Affiliated Entity [Member]									
Oil and Gas Investments (Details) [Line Items]									
Acquisition Costs, Period Cost				$ 4,100,000					

Oil and Gas Investments (Details) - Business Acquisition, Pro Forma Information - USD ($)	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Business Acquisition, Pro Forma Information [Abstract]		
Revenues	$ 43,067,089	$ 29,484,426
Net income	$ 18,604,782	$ 9,864,799

Debt (Details) - USD ($)					12 Months Ended	
	Aug. 31, 2018	Jan. 16, 2018	Jul. 25, 2017	Feb. 28, 2017	Dec. 31, 2018	Dec. 31, 2017
Debt (Details) [Line Items]						
Long-term Line of Credit, Noncurrent					$ 39,500,000	$ 0
Lines of Credit, Fair Value Disclosure					39,500,000	
Revolving Credit Facility [Member]						
Debt (Details) [Line Items]						
Debt Instrument, Face Amount	$ 60,000,000					
Line of Credit Facility, Borrowing Capacity, Description	The commitment amount may be increased up to $100 million with Lender approval.					
Line of Credit Facility, Commitment Fee Percentage	0.50%					
Line of Credit Facility, Commitment Fee Amount	$ 300,000					
Line of Credit Facility, Commitment Fee in Excess of Revolver Amount, Percentage	0.50%					
Line of Credit Facility, Unused Capacity, Commitment Fee Percentage	0.50%					
Debt Instrument, Maturity Date	Aug. 31, 2021					
Line of Credit Facility, Maximum Borrowing Capacity					$ 40,000,000	
Line of Credit Facility, Interest Rate at Period End					6.25%	
Line of Credit Facility, Collateral	The Credit Facility is secured by a mortgage and first lien position on at least 90% of the Partnership’s producing wells.					

Line of Credit Facility, Covenant Terms	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					
Line of Credit Facility, Covenant Compliance					The Partnership was in compliance with the applicable covenants at December 31, 2018.	
Line of Credit [Member]						
Debt (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.		
Notes Payable to Banks [Member]						
Debt (Details) [Line Items]						
Debt Instrument, Face Amount		$ 25,000,000				
Guarantor Obligations, Origin and Purpose		Glade M. Knight and David S. McKenney, the General Partner’s Chief Executive Officer and Chief Financial Officer, respectively, had guaranteed repayment of the Term Loan and did not receive any consideration in exchange for providing this guarantee.				
Debt Instrument, Payment Terms		Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty.				
London Interbank Offered Rate (LIBOR) [Member] | Notes Payable to Banks [Member]						
Debt (Details) [Line Items]						
Debt Instrument, Basis Spread on Variable Rate		2.00%				
London Interbank Offered Rate (LIBOR) [Member] | Minimum [Member] | Revolving Credit Facility						

[Member]						
Debt (Details) [Line Items]						
Debt Instrument, Basis Spread on Variable Rate	2.75%					
London Interbank Offered Rate (LIBOR) [Member] | Maximum [Member] | Revolving Credit Facility [Member]						
Debt (Details) [Line Items]						
Debt Instrument, Basis Spread on Variable Rate	3.75%					

Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis	Dec. 31, 2018 USD ($)
Fair Value, Inputs, Level 1 [Member]	
Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Line Items]	
Commodity derivatives - current assets	$ 0
Commodity derivatives - current liabilities	0
Commodity derivatives - noncurrent assets	0
Commodity derivatives - noncurrent liabilities	0
Total	0
Fair Value, Inputs, Level 2 [Member]	
Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Line Items]	
Commodity derivatives - current assets	644,786
Commodity derivatives - current liabilities	0
Commodity derivatives - noncurrent assets	234,831
Commodity derivatives - noncurrent liabilities	0
Total	879,617
Fair Value, Inputs, Level 3 [Member]	
Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Line Items]	
Commodity derivatives - current assets	0
Commodity derivatives - current liabilities	0
Commodity derivatives - noncurrent assets	0
Commodity derivatives - noncurrent liabilities	0
Total	$ 0

Risk Management (Details) - USD ($)	12 Months Ended
	Dec. 31,

	Dec. 31, 2018	2017
Derivative Instruments and Hedging Activities Disclosure [Abstract]		
Discussion of Price Risk Derivative Risk Management Policy	Under the Credit Facility, the Partnership is required to maintain a risk management program, covering at least 50% of the Partnership's total estimated monthly production of oil and natural gas through the maturity date of August 31, 2021.	
Derivative Asset	$ 900,000	
Derivative, Gain (Loss) on Derivative, Net	$ 879,617	$ 0

Risk Management (Details) - Schedule of Derivative Instruments	12 Months Ended
	Dec. 31, 2018 USD ($) $ / item bbl
Derivative [Line Items]	
Oil (Barrels) (in Barrels (of Oil)) | bbl	373,000
Fair Value of Asset / (Liability) (in Dollars) | $	$ 879,617
Price Risk Derivative [Member] | 01/01/19 - 12/31/19 [Member] | Costless Collar Agreements #1 [Member]	
Derivative [Line Items]	
Basis	NYMEX
Oil (Barrels) (in Barrels (of Oil)) | bbl	266,000
Floor Price	45.00
Ceiling Price	60.35
Fair Value of Asset / (Liability) (in Dollars) | $	$ 644,786
Price Risk Derivative [Member] | 01/01/20 - 06/30/20 [Member] | Costless Collar Agreements #2 [Member[	
Derivative [Line Items]	
Basis	NYMEX
Oil (Barrels) (in Barrels (of Oil)) | bbl	107,000
Floor Price	45.00
Ceiling Price	61.20
Fair Value of Asset / (Liability) (in Dollars) | $	$ 234,831

Capital Contribution and Partners' Equity (Details) - USD ($)		1 Months Ended	7 Months Ended	12 Months Ended		24 Months Ended
	Dec. 30, 2016	Oct. 31, 2017	Jul. 25, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018
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				7,900,000
Proceeds from Issuance of Common Limited Partners Units				$ 87,634,447	$ 57,014,432	$ 154,500,000
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units						$ 144,600,000
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				$ 6,200,000		
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)				$ 1.396164	$ 0.598357	
Distribution Made to Limited Partner, Cash Distributions Paid				$ 7,044,859	$ 1,458,398	

Related Parties (Details) - USD ($)			12 Months Ended	
	Dec. 28, 2018	Feb. 01, 2018	Dec. 31, 2018	Dec. 31, 2017
Related Parties (Details) [Line Items]				
Related Party Transaction, Description of Transaction			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.		
Due to Related Parties, Current				$ 212,117	$ 5,283,623
Proceeds from Related Party Debt				7,000,000	0
General Partner [Member]					
Related Parties (Details) [Line Items]					
Due to Related Parties, Current				135,000	
Related Party Transaction, Selling, General and Administrative Expenses from Transactions with Related Party				402,000	$ 57,000
Energy 11 [Member]					
Related Parties (Details) [Line Items]					
Due to Related Parties, Current				77,000	
Related Party Transaction, Selling, General and Administrative Expenses from Transactions with Related Party				252,000	
Management Fee [Member] | General Partner [Member]					
Related Parties (Details) [Line Items]					
Due to Related Parties, Current				537,000	
Consulting Services Provided to General Partner [Member] | President [Member]					
Related Parties (Details) [Line Items]					
Payment Made By Related Party to Others				$ 500,000	
Bakken Assets [Member] | Acquisition No. 1 [Member]					
Related Parties (Details) [Line Items]					
Proceeds from Related Party Debt		$ 7,000,000			
Bakken Assets [Member] | Affiliated Entity [Member]					
Related Parties (Details) [Line Items]					
Asset Disposal Fee, Related Party, Percentage				5.00%	
Capital Unit, Class B [Member]					
Related Parties (Details) [Line Items]					
In connection with termination of agreements with REI, the General Partner issued 500 of its non-voting Class B Units to entities controlled by related parties (in Shares)	500				
Payment made by entities controlled by related parties to General Partner for non-voting Class B Units	$ 500				
In connection with termination of agreements with REI, entities controlled by related parties have acquired a non-voting interest in the General Partner	50.00%				

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details)	12 Months Ended	
	Dec. 31, 2018 Boe $ / bbl $ / Mcf	
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid		

Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	1,252,630	[1]
Development Wells Drilled, Net Productive	56	
Proved Developed and Undeveloped Reserve, Net (Energy), Period Increase (Decrease)	(1,899,972)	[2]
Acquisition No. 1 [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	8,427,708	[3]
Acquisition No. 2 [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	7,279,846	[4]
Before Price Differentials [Member] | Oil [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices (in Dollars per Barrel (of Oil)) | $ / bbl	65.56	
Before Price Differentials [Member] | Natural Gas [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices (in Dollars per Barrel (of Oil)) | $ / Mcf	3.10	
Including Effects of Price Differential Adjustments [Member] | Oil [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices (in Dollars per Barrel (of Oil)) | $ / bbl	59.56	
Including Effects of Price Differential Adjustments [Member] | Natural Gas [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices (in Dollars per Barrel (of Oil)) | $ / Mcf	2.43	

Including Effects of Price Differential Adjustments [Member] | Natural Gas Liquids [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices (in Dollars per Barrel (of Oil)) | $ / bbl	20.25	
Proved Reserves [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	870,000	
Proved Reserves [Member] | Acquisition No. 1 [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	11,257,000	
Proved Reserves [Member] | Acquisition No. 2 [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	11,792,000	
Proved Reserves [Member] | Adjustments Related to Changes in Future Drill Schedule [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	1,248,000	
Proved Reserves [Member] | Adjustments Related to Prices [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	7,000	
Proved Reserves [Member] | Adjustments Related to Well Performance [Member]		
Supplementary Information on Oil,		

Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	385,000	
Proved Undeveloped Reserves [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	1,253,000	
Proved Undeveloped Reserves [Member] | Acquisition No. 1 [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	8,428,000	
Proved Undeveloped Reserves [Member] | Acquisition No. 2 [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	7,280,000	
Proved Undeveloped Reserves [Member] | Adjustments Related to Changes in Future Drill Schedule [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	1,249,000	
Proved Undeveloped Reserves [Member] | Adjustments Related to Prices [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Proved Developed and Undeveloped Reserve, Revision of Previous Estimate (Energy)	4,000	
Measurement Input, Discount Rate [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid		

Reserves (Unaudited) (Details) [Line Items]		
Future Cash Flows Measurement Input	10.00%	

[1] Revisions to previous estimates, from the respective closing dates for Acquisitions No. 1 and No. 2, increased PUDs by a net amount of 1,253 MBOE. These revisions result from 1,249 MBOE of upward adjustments attributable to changes in the future drill schedule and 4 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2. There were no adjustments related to well performance.

[2] Since the Partnership completed its first acquisition, 56 wells have either been completed or are in-process by the Partnership's operators. This development has led to 1,900 MBOE of PUDs being converted to proved developed reserves from February 1, 2018 to December 31, 2018.

[3] The Partnership acquired 8,428 MBOE attributable to PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

[4] The Partnership acquired 7,280 MBOE attributable to PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Capitalized Costs Relating to Oil and Gas Producing Activities Disclosure	Dec. 31, 2018 USD ($)
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]	
Properties acquired	$ 68,481,176
Development	15,461,555
	186,968,473
Accumulated depreciation, depletion and amortization	(4,889,806)
Net capitalized costs	182,078,667
Producing Properties [Member]	
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]	
Properties acquired	$ 103,025,742

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Schedule of Proved Developed and Undeveloped Oil and Gas Reserve Quantities	12 Months Ended	
	Dec. 31, 2018 Boe bbl Mcf	
Reserve Quantities [Line Items]		
Balance	0	
Balance proved developed reserves (in Barrels of Oil Equivalent) | Boe	8,356,778	
Balance proved undeveloped reserves (in Barrels of Oil Equivalent) | Boe	15,060,212	
Balance proved undeveloped reserves (in Barrels of Oil Equivalent) | Boe	15,060,212	
Balance proved undeveloped reserves (in Barrels of Oil Equivalent) | Boe	0	
Revisions of previous estimates (in Barrels of Oil Equivalent) | Boe	1,252,630	[1]
Conversion to proved developed reserves (in Barrels of Oil Equivalent) | Boe	(1,899,972)	[2]
Extensions, discoveries and other additions	0	
Revisions of previous estimates	869,507	[3]

Production	(501,150)	
Balance	23,416,990	
Acquisition No. 1 [Member]		
Reserve Quantities [Line Items]		
Proved undeveloped reserves acquired (in Barrels of Oil Equivalent) | Boe	8,427,708	[4]
Acquisition	11,257,058	[5]
Acquisition No. 2 [Member]		
Reserve Quantities [Line Items]		
Proved undeveloped reserves acquired (in Barrels of Oil Equivalent) | Boe	7,279,846	[6]
Acquisition	11,791,575	[7]
Oil [Member]		
Reserve Quantities [Line Items]		
Balance	0	
Balance proved developed reserves	6,982,216	
Balance proved undeveloped reserves	13,282,224	
Extensions, discoveries and other additions	0	
Revisions of previous estimates	653,770	[3]
Production	(405,581)	
Balance	20,264,440	
Oil [Member] | Acquisition No. 1 [Member]		
Reserve Quantities [Line Items]		
Acquisition	9,717,859	[5]
Oil [Member] | Acquisition No. 2 [Member]		
Reserve Quantities [Line Items]		
Acquisition	10,298,392	[7]
Natural Gas [Member]		
Reserve Quantities [Line Items]		
Balance | Mcf	0	
Balance proved developed reserves | Mcf	4,126,780	
Balance proved undeveloped reserves | Mcf	5,836,010	
Extensions, discoveries and other additions | Mcf	0	
Revisions of previous estimates | Mcf	545,023	[3]
Production | Mcf	(319,445)	
Balance | Mcf	9,962,790	
Natural Gas [Member] | Acquisition No. 1 [Member]		
Reserve Quantities [Line Items]		
Acquisition | Mcf	4,957,715	[5]
Natural Gas [Member] | Acquisition No. 2 [Member]		
Reserve Quantities [Line Items]		
Acquisition | Mcf	4,779,497	[7]
Natural Gas Liquids [Member]		
Reserve Quantities [Line Items]		

Balance	0	
Balance proved developed reserves	686,765	
Balance proved undeveloped reserves	805,320	
Extensions, discoveries and other additions	0	
Revisions of previous estimates	124,901	[3]
Production	(42,329)	
Balance	1,492,085	
Natural Gas Liquids [Member] | Acquisition No. 1 [Member]		
Reserve Quantities [Line Items]		
Acquisition	712,913	[5]
Natural Gas Liquids [Member] | Acquisition No. 2 [Member]		
Reserve Quantities [Line Items]		
Acquisition	696,600	[7]

[1] Revisions to previous estimates, from the respective closing dates for Acquisitions No. 1 and No. 2, increased PUDs by a net amount of 1,253 MBOE. These revisions result from 1,249 MBOE of upward adjustments attributable to changes in the future drill schedule and 4 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2. There were no adjustments related to well performance.

[2] Since the Partnership completed its first acquisition, 56 wells have either been completed or are in-process by the Partnership's operators. This development has led to 1,900 MBOE of PUDs being converted to proved developed reserves from February 1, 2018 to December 31, 2018.

[3] Revisions to previous estimates increased proved reserves by a net amount of 870 MBOE. These revisions result from 1,248 MBOE of upward adjustments attributable to changes in the future drill schedule and 7 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2018 to the drill schedules and oil, natural gas and NGL prices at the dates of Acquisitions No. 1 and No. 2, which were partially offset by 385 MBOE of downward adjustments related to well performance post acquisition-closing dates.

[4] The Partnership acquired 8,428 MBOE attributable to PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

[5] The Partnership acquired 11,257 MBOE of reserves attributable to producing developed wells and PUDs in conjunction with Acquisition No. 1 (see Note 3. Oil and Gas Investments).

[6] The Partnership acquired 7,280 MBOE attributable to PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

[7] The Partnership acquired 11,792 MBOE of reserves attributable to producing developed wells and PUDs in conjunction with Acquisition No. 2 (see Note 3. Oil and Gas Investments).

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure - USD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]		
Future cash inflows	$ 1,256,302	
Future production costs	(342,615)	
Future development costs	(102,210)	
Future net cash flows	811,477	
10% annual discount	(440,982)	
Standardized measure of discounted future net cash flows	$ 370,495	$ 0

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure (Parentheticals)	12 Months Ended
	Dec. 31, 2018

Measurement Input, Discount Rate [Member]	
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [Line Items]	
Annual discount	10.00%

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows $ in Thousands	12 Months Ended Dec. 31, 2018 USD ($)
Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows [Abstract]	
Standardized measure at beginning of period	$ 0
Acquisition of reserves	273,568
Sales of oil, natural gas and NGLs, net of production costs	(17,733)
Net changes in prices and production costs	71,883
Development costs incurred during the period	15,462
Revisions to previous estimates	11,491
Accretion of discount	15,174
Change in estimated future development costs	650
Standardized measure of discounted future net cash flows	$ 370,495

Quarterly Financial Data (Unaudited) (Details) - Quarterly Financial Information - USD ($)	3 Months Ended								12 Months Ended	
	Dec. 31, 2018 [1]	Sep. 30, 2018 [1]	Jun. 30, 2018 [1]	Mar. 31, 2018 [1]	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Quarterly Financial Information [Abstract]										
Total revenue	$ 9,189,155	$ 5,503,706	$ 7,531,096	$ 3,497,079	$ 0	$ 0	$ 0	$ 0	$ 25,721,036	$ 0
Net income (loss)	$ 3,589,444	$ 2,087,725	$ 3,400,535	$ 1,288,325	$ (500,561)	$ 12,524	$ (15,675)	$ (6,535)	$ 10,366,029	$ (510,247)
Basic and diluted net income (loss) per common share (in Dollars per share)	$ 0.51	$ 0.37	$ 0.82	$ 0.38	$ (0.18)	$ 0.01	$ 0	$ 0	$ 2.04	$ (0.48)

[1] The Partnership did not acquire its first operating asset until February 1, 2018.

Subsequent Events (Details) - Subsequent Event [Member] $ / shares in Units, shares in Millions, $ in Millions	1 Months Ended		
	Mar. 31, 2019 USD ($) Boe $ / shares shares	Feb. 28, 2019 USD ($) $ / shares shares	Jan. 31, 2019 USD ($) $ / shares shares
Subsequent Events (Details) [Line Items]			
Distribution Made to Limited Partner, Cash Distributions Paid	$ 1.1	$ 0.9	$ 0.8

Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share) | $ / shares	$ 0.134247	$ 0.107397	$ 0.107397
Price Risk Derivative [Member] | April 2019 to September 2020 [Member]			
Subsequent Events (Details) [Line Items]			
Derivative, Nonmonetary Notional Amount, Energy Measure (in Barrels of Oil Equivalent) | Boe	108,000		
Best-Efforts Offering [Member]			
Subsequent Events (Details) [Line Items]			
Partners' Capital Account, Units, Sale of Units (in Shares) | shares	0.3	0.2	0.3
Proceeds from Issuance of Common Limited Partners Units	$ 6.9	$ 4.4	$ 5.1
Proceeds, Net of Selling Commissions and Marketing Expenses, from Issuance of Common Limited Partners Units	$ 6.5	$ 4.2	$ 4.8

ENERGY RESOURCES 12, L.P. (Filer) CIK: 0001696088 (see all company filings)
IRS No.: **814805237** | State of Incorp.: **DE** | Fiscal Year End: **1231**
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SIC: **1311** Crude Petroleum & Natural Gas
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