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Energy 11, L.P. (Filer) CIK: 0001581552

Document And Entity Information - USD ($)	12 Months Ended		
	Dec. 31, 2017	Mar. 08, 2018	Jun. 30, 2017
Document and Entity Information [Abstract]			
Entity Registrant Name	Energy 11, L.P.		
Document Type	10-K		
Current Fiscal Year End Date	--12-31		
Entity Common Stock, Shares Outstanding		18,973,474	
Entity Public Float			$ 0
Amendment Flag	false		
Entity Central Index Key	0001581552		
Entity Current Reporting Status	Yes		
Entity Voluntary Filers	No		
Entity Filer Category	Smaller Reporting Company		
Entity Well-known Seasoned Issuer	No		
Document Period End Date	Dec. 31, 2017		
Document Fiscal Year Focus	2017		
Document Fiscal Period Focus	FY		

Consolidated Balance Sheets - USD ($)	Dec. 31, 2017	Dec. 31, 2016
Assets		
Cash and cash equivalents	$ 11,090,846	$ 86,800,596
Oil, natural gas and natural gas liquids revenue receivable	6,219,193	2,718,296
Other current assets	162,930	10,038,221
Total Current Assets	17,472,969	99,557,113
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization of $24,934,190 and $9,908,800, respectively	321,766,616	151,554,972
Total Assets	339,239,585	251,112,085
Liabilities		
Accounts payable and accrued expenses	2,733,131	2,622,400
Derivative liability	1,026,965	0
Total Current Liabilities	3,760,096	2,622,400
Revolving credit facility	20,000,000	0
Asset retirement obligations	1,226,879	70,623
Total Liabilities	24,986,975	2,693,023
Partners' Equity		
Limited partners' interest (18,973,474		

and 14,582,963 common units issued and outstanding, respectively)	314,254,337	248,420,789
General partner's interest	(1,727)	(1,727)
Class B Units (62,500 units issued and outstanding, respectively)	0	0
Total Partners' Equity	314,252,610	248,419,062
Total Liabilities and Partners' Equity	$ 339,239,585	$ 251,112,085

Consolidated Balance Sheets (Parentheticals) - USD ($)	Dec. 31, 2017	Dec. 31, 2016
Oil and natural gas properties, accumulated depreciation, depletion and amortization (in Dollars)	$ 24,934,190	$ 9,908,800
Limited partners' interest, common units issued	18,973,474	14,582,963
Limited partners' interest, common units outstanding	18,973,474	14,582,963
Class B Units, units issued	62,500	62,500
Class B Units, units outstanding	62,500	62,500

Consolidated Statements of Operations - USD ($)	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Oil, natural gas and natural gas liquids revenues	$ 41,012,740	$ 20,365,338
Production expenses	12,034,976	5,811,111
Production taxes	3,406,171	1,870,212
General, administrative and other expense	909,326	2,254,909
Depreciation, depletion, amortization and accretion	15,084,504	9,526,865
Total operating costs and expenses	31,434,977	19,463,097
Operating income	9,577,763	902,241
Loss on derivatives	(1,026,965)	0
Interest expense, net	(654,476)	(6,132,805)
Total other expense, net	(1,681,441)	(6,132,805)
Net income (loss)	$ 7,896,322	$ (5,230,564)
Basic and diluted net income (loss) per common unit (in Dollars per share)	$ 0.44	$ (0.69)
Weighted average common units outstanding - basic and diluted (in Shares)	18,112,836	7,538,180

Consolidated Statements of Partners' Equity - USD ($)	Total	Member Units [Member] Capital Unit, Class B [Member]	Limited Partner [Member]	General Partner [Member]
Balance at Dec. 31, 2015	$ 75,278,574	$ 0	$ 75,280,301	$ (1,727)
Net proceeds from issuance of common units	188,820,033		188,820,033	
Distributions declared and to common units paid	(10,448,981)		(10,448,981)	
Net Loss	(5,230,564)		(5,230,564)	
Balance at Dec. 31, 2016	248,419,062	0	248,420,789	(1,727)
Net proceeds from issuance of common units	82,515,450		82,515,450	
Distributions declared and to common units paid	(24,578,224)		(24,578,224)	
Net Loss	7,896,322		7,896,322	
Balance at Dec. 31, 2017	$ 314,252,610	$ 0	$ 314,254,337	$ (1,727)

Consolidated Statements of Partners' Equity (Parentheticals) - $ / shares	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Distributions declared and paid, per common unit	$ 1.361643	$ 1.400000

Consolidated Statements of Cash Flows - USD ($)	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Cash flow from operating activities:		
Net income (loss)	$ 7,896,322	$ (5,230,564)
Adjustments to reconcile net income (loss) to cash from operating activities:		
Depreciation, depletion, amortization and accretion	15,084,504	9,526,865
Loss on derivatives	1,026,965	0
Non-cash expenses, net	102,409	4,017,238
Changes in operating assets and liabilities:		
Oil, natural gas and natural gas liquids revenue receivable	(3,500,897)	(2,004,351)
Other current assets	(44,279)	(38,221)
Accounts payable and accrued expenses	100,972	678,417
Net cash flow provided by operating activities	20,665,996	6,949,384
Cash flow from investing activities:		
Cash paid for acquisition of oil and natural gas properties	(99,250,130)	(1,000,000)
Deposit for potential acquisition	0	(10,000,000)
Additions to oil and natural gas properties	(2,262,619)	(1,644,186)
Net cash flow used in investing activities	(101,512,749)	(12,644,186)
Cash flow from financing activities:		
Cash paid for loan costs	(87,742)	(250,000)
Net proceeds from revolving credit facility	20,000,000	0
Net proceeds related to issuance of units	82,510,325	188,825,158
Distributions paid to limited partners	(24,578,224)	(10,448,981)
Payments on note payable	(72,707,356)	(88,917,833)
Net cash flow provided by (used in) financing activities	5,137,003	89,208,344
Increase (decrease) in cash and cash equivalents	(75,709,750)	83,513,542
Cash and cash equivalents, beginning of period	86,800,596	3,287,054
Cash and cash equivalents, end of period	11,090,846	86,800,596
Interest paid	557,431	2,171,573
Supplemental non-cash information:		
Increase in note payable, payment of contingent consideration	0	5,000,000
Decrease in note payable, settlement of pre-close activity	292,644	1,082,167
Acquisition No. 2 [Member]		
Supplemental non-cash information:		
Note payable assumed in Acquisition	40,000,000	0
Acquisition No. 3 [Member]		
Supplemental non-cash information:		
Note payable assumed in Acquisition	$ 33,000,000	$ 0

Partnership Organization	12 Months Ended
	Dec. 31, 2017
Disclosure Text Block [Abstract]	
Organization, Consolidation and Presentation of Financial Statements Disclosure [Text Block]	**Note 1. Partnership Organization** Energy 11, L.P. (the "Partnership") is a Delaware limited partnership formed to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership completed its best-efforts offering on April 24, 2017 with a total of approximately 19 million common units sold for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million. As of December 31, 2017, the Partnership owned an approximate 26-27% non-operated working interest in 215 currently producing wells, six wells currently being drilled and approximately 247 future development sites in the Sanish field located in Mountrail County, North Dakota (collectively, the "Sanish Field Assets"), which is part of the Bakken shale formation in the Greater Williston Basin. Whiting Petroleum Corporation ("Whiting"), one of the largest producers in the basin, operates substantially all of the Sanish Field Assets. The general partner of the Partnership is Energy 11 GP, LLC (the "General Partner"). The General Partner manages and controls the business affairs of the Partnership. David Lerner Associates, Inc. (the "Dealer Manager") was the dealer manager for the offering of the common units. The Partnership's fiscal year ends on December 31.

Summary of Significant Accounting Policies	12 Months Ended
	Dec. 31, 2017
Accounting Policies [Abstract]	
Significant Accounting Policies [Text Block]	**Note 2. Summary of Significant Accounting Policies** *Basis of Presentation* The accompanying consolidated financial statements of the Partnership have been prepared in accordance with United States generally accepted accounting principles ("US GAAP"). The consolidated financial statements include the accounts of the Partnership and its subsidiaries. *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. *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 our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates 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, 2017, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2017, the Partnership's oil, natural gas and NGL sales were through two operators. Whiting Petroleum Corporation ("Whiting") is the operator of 99% of the Partnership's properties. 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

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 years ended December 31, 2017 and 2016, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2015	$	105,459
Well additions		1,868
Accretion		9,689
Revisions in estimated cash flows		(46,393)
Balance as of December 31, 2016		70,623
Liabilities incurred on January 11, 2017 (acquisition)		781,628
Liabilities incurred on March 31, 2017 (acquisition)		289,827
Well additions		22,582
Accretion		59,114
Revisions in estimated cash flows		3,105
Balance as of December 31, 2017	$	1,226,879

Income Tax

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

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

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

The Partnership follows the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where the Partnership has taken less than its share of production.

Environmental Costs

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

Environmental liabilities are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At December 31, 2017 and 2016, there were no such costs accrued.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of 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 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

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

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.

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 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, 2017 and 2016. As a result, basic and diluted outstanding common units were the same. The Class B Units and Incentive Distribution Rights 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 January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2017-01, Business Combinations (Topic

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

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, that amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. Throughout 2016 and 2017, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 2017-14, respectively, to clarify specific topics originally described in ASU 2014-09. In August 2015, the FASB issued ASU No. 2015-14, which deferred the effective date of ASU 2014-09 to annual and interim periods beginning after December 15, 2017, and permitted early application for annual reporting periods beginning after December 15, 2016. The Partnership adopted this standard on January 1, 2018 using the modified retrospective approach. Based on its assessment of this standard, the Partnership does not believe the standard will have a significant change to the amount or timing of the recording of revenue in its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the existing accounting standards for lease accounting, including requiring lessees to recognize most leases on their balance sheets as right-of-use assets and lease liabilities. The standard is effective for annual and interim periods beginning after December 15, 2018 with early adoption permitted. The Partnership expects to adopt this standard as of January 1, 2019. The Partnership is still evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

Oil and Gas Investments	12 Months Ended Dec. 31, 2017
Oil and Gas Property [Abstract]	
Oil and Gas Properties [Text Block]	**Note 3. Oil and Gas Investments**

Note 3. Oil and Gas Investments

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

On January 11, 2017, the Partnership completed its purchase ("Acquisition No. 2") of an additional approximate 11% non-operated working interest in the Sanish Field Assets for approximately $128.5 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 2 with the delivery of a promissory note in favor of the sellers of $40.0 million, which was paid in full in February 2017. The Partnership accounted for Acquisition No. 2 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the year ended December 31, 2017 were approximately $43,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.8 million in conjunction with this acquisition. Acquisition No. 2 increased the Partnership's non-operated working interest in the Sanish Field Assets to approximately 22-23%.

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

As of December 31, 2017, the Partnership owned an approximate 26-27% non-operated working interest in 215 currently producing wells, six wells currently being drilled and approximately 247 future development sites in the Sanish Field Assets.

The following unaudited pro forma financial information for the years ended December 31, 2017 and 2016 have been prepared as if Acquisitions No. 2 and No. 3 of the Sanish Field Assets had occurred on January 1, 2016. The unaudited pro forma financial information was derived from the historical Statements of Operations of the Partnership and the historical information provided by the sellers. The unaudited pro forma financial information does not purport to be indicative of the results of operations that would have occurred had the acquisitions of the Sanish Field Assets and related financings occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

	Year Ended December 31, 2017	Year Ended December 31, 2016

	(Unaudited)	(Unaudited)
Revenues	$ 43,355,472	$ 47,506,576
Net income	$ 7,957,922	$ 384,443

In October and November 2017, the Partnership elected to participate in the drilling and completion of six new wells. Four wells are being drilled and will be operated by Oasis Petroleum, Inc. (NYSE: OAS), and the Partnership will have an estimated approximate 7-9% non-operated working interest in these four wells. The other two wells are being drilled and will be operated by Whiting, and the Partnership will have an estimated approximate 29% non-operated working interest in these two wells. All six wells were started in late 2017 and are anticipated to be completed in the first half of 2018. In total, capital expenditures for the drilling and completion of the six wells discussed above are estimated to be approximately $7.0 million, of which approximately $1.3 million had been incurred as of December 31, 2017.

Debt	12 Months Ended
	Dec. 31, 2017
Debt Disclosure [Abstract]	
Debt Disclosure [Text Block]	**Note 4. Debt**

Note 4. Debt

As part of the financing for Acquisition No. 1 completed on December 18, 2015, the Partnership executed a note in favor of the sellers ("Seller Note 1") in the original principal amount of $97.5 million. On June 23, 2016, Seller Note 1 was increased by $5.0 million to satisfy the contingent payment due to the sellers as defined in the First Amendment of the Interest Purchase Agreement. The Partnership was given the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to satisfy the contingent payment in full by paying to the sellers $5.0 million at the time of election or by increasing the amount of Seller Note 1 by $5.0 million. On June 23, 2016, the Partnership exercised that right by increasing the amount of Seller Note 1 by $5.0 million. If the Partnership had not exercised the one-time right, the contingent payment would have ranged from $0 to $95 million depending on the average of the monthly NYMEX:CL strip prices as of December 31, 2017 for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022. Also in accordance with Seller Note 1, because the Partnership had not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership paid a deferred origination fee equal to $250,000 during the three months ended June 30, 2016. The deferred origination fee was amortized and expensed in full during the third quarter of 2016 and is included in "Interest expense, net" in the consolidated statements of operations. On September 29, 2016, the Partnership paid Seller Note 1 in full.

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

As part of the financing for Acquisition No. 3 completed on March 31, 2017, the Partnership executed a note ("Seller Note 3") in favor of the sellers in the original principal amount of $33.0 million. Seller Note 3 bore interest at 5% per annum and was payable in full no later than August 1, 2017 ("Maturity Date"). In July 2017, the Partnership and the sellers executed a First Amendment to Seller Note 3 ("Amended Note"), which extended the maturity date to June 29, 2018 ("Extended Maturity Date") provided the Partnership meets certain terms and conditions of the Amended Note, including making a $2.0 million payment on the outstanding principal balance by July 31, 2017. The $2.0 million payment was made by the Partnership on July 31, 2017. The Amended Note bore interest at 5% per annum. The Partnership paid the outstanding balance on the Amended Note of approximately $5.9 million, including interest, on November 21, 2017 in conjunction with the closing on the credit facility discussed below. There was no penalty for prepayment of the Amended Note.

On November 21, 2017, the Partnership, as the borrower, entered into a loan agreement (the "Loan Agreement") with Bank SNB (the "Lender"), which provides for a revolving credit facility (the "Credit Facility") with an approved initial commitment amount of $20 million (the "Revolver Commitment Amount"), subject to borrowing base restrictions. The commitment amount may be increased up to $75 million with Lender approval. The Partnership paid an origination fee of 0.30% of the Revolver Commitment Amount, or $60,000, and is subject to additional origination fees of 0.30% for any borrowings made in excess of the Revolver Commitment Amount. The Partnership is also required to pay an unused facility fee 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 November 21, 2019.

Under the Loan Agreement, the initial borrowing base is $30 million. However, the borrowing base is subject to redetermination semi-annually, in February and August, based upon the Lender's analysis of the Partnership's proven oil and natural gas reserves. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time. The interest rate, subject to certain exceptions, is equal to the London Inter-Bank Offered Rate (LIBOR) plus a margin ranging from 2.50% to 3.50%, depending upon the Partnership's borrowing base utilization, as calculated under the terms of the Loan Agreement. At December 31, 2017, the interest rate for the Credit Facility was 4.76%.

At closing, the Partnership borrowed $20.0 million. The proceeds were used to pay closing costs, the $5.9 million outstanding balance of the note executed in conjunction with the Acquisition No. 3, and the $1.0 million deferred purchase price due to the seller in conjunction with Acquisition No. 1. The Credit Facility will provide additional liquidity for capital investments, including the drilling and completion of the six wells described in "Note 3. Oil and Gas Investments," 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 80% of the Partnership's producing wells.

The Credit Facility contains mandatory prepayment requirements, customary affirmative and negative covenants and events of default. The financial covenants include:

- a maximum leverage ratio

- a minimum current ratio
- maximum distributions

The Partnership was in compliance with the applicable covenants at December 31, 2017.

As of December 31, 2017 and 2016, the Partnership's outstanding debt balance was $20.0 million and $0, respectively. The outstanding balance at December 31, 2017 of $20.0 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, 2017
Fair Value Disclosures [Abstract]	
Fair Value Disclosures [Text Block]	**Note 5. Fair Value of Financial Instruments**

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, 2017 and 2016, 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, 2016, 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, 2017.

	Fair Value Measurements at December 31, 2017		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity derivatives - current assets	$ -	$ -	$ -
Commodity derivatives - current liabilities	-	(1,026,965)	-
Total	$ -	$ (1,026,965)	$ -

The Level 2 instruments presented in the table above consist of Partnership's costless collar commodity derivative instruments. The fair value of the Partnership's derivative financial instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The fair value of the commodity derivatives noted above are included in the Partnership's consolidated balance sheet in Derivative liability at December 31, 2017. 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, accounts receivable, accounts payable and accrued liabilities reflect these items' cost, which approximates fair value based on the timing of the anticipated cash flows, current market conditions and short-term maturity of these instruments. In addition, see Note 4. Debt for the fair value discussion on the Partnership's debt.

Risk Management	12 Months Ended
	Dec. 31, 2017
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Derivative Instruments and Hedging Activities Disclosure [Text Block]	See below

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. In December 2017, the Partnership began to utilize derivative contracts to manage the commodity price risk on the Partnership's future oil production it will produce and sell and to reduce the effect of volatility in commodity price changes to provide a base level of cash flow from operations. All derivative instruments are recorded on the Partnership's balance sheet as assets or liabilities measured at fair value. As of December 31, 2017, the Partnership's costless collar derivative instruments were in a net loss position; therefore, a current liability of approximately $1.0 million, which approximates its fair value, was recorded. 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 are recognized on the Partnership's consolidated statements of operations as a gain or loss on derivative instruments. The Partnership has recognized a mark-to-market loss of approximately $1.0 million for the year ended December 31, 2017, recorded to the consolidated statements of operations as Loss 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 derivative contracts are costless collars, which are used to establish floor and ceiling prices on future anticipated oil production. The Partnership did not pay or receive a premium related to the costless collar agreements. The contracts are settled monthly and there were no settlement payables or receivables at December 31, 2017. The follow table reflects open costless collar agreements as of December 31, 2017.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)	Fair Value of Asset / (Liability) at December 31, 2017
01/01/18 - 12/31/18	NYMEX	294,000	$ 52.00 / 57.05	$ (1,011,684)
01/01/18 - 12/31/18	NYMEX	36,000	$ 55.00 / 61.35	(15,281)
				$ (1,026,965)

All of 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, 2017
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 was reimbursed for its documented third party out-of-pocket expenses incurred in organizing the Partnership and offering the common units.

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

Under the agreement with the Dealer Manager, the Dealer Manager received a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership. Based on the common units sold through December 31, 2017, the total contingent fee is approximately $15.0 million.

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

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per 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, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;

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

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed below.

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

For the year ended December 31, 2017, the Partnership paid distributions of $1.361643 per common unit, or $24.6 million. Effective with the November 29, 2017 distribution, the General Partner approved an adjustment to the annualized distribution rate to an annualized return of six percent based on a limited partner's Net Investment Amount of $20.00 per common unit. The difference between any distribution and an annualized return of seven percent based on the Net Investment Amount is required to be paid before final Payout occurs as defined above. As of December 31, 2017, the unpaid Payout Accrual totaled $0.034521 per common unit, or approximately $0.7 million. For the year ended December 31, 2016, the Partnership paid distributions of $1.400000 per common unit, or $10.4 million.

Management Agreement	12 Months Ended Dec. 31, 2017
Contractors [Abstract]	
Long-term Contracts or Programs Disclosure [Text Block]	**Note 8. Management Agreement**

Note 8. Management Agreement

At the initial closing of the sale of common units on August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with E11 Management LLC (the "Former Manager") to provide management and operating services regarding substantially all aspects of the Partnership. Under the Management Agreement, the Former Manager agreed to provide management and operating services to the Partnership in exchange for a monthly fee. In addition, the Partnership issued 100,000 Class B units to an affiliate of the Former Manager upon entering into the Management Agreement. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Distributions above.

Since substantially all the Partnership's properties are operated by Whiting and the Partnership only owns a non-operating working interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting. Consequently, the Partnership terminated the Management Agreement in 2016. In conjunction with the termination, 37,500 of the Class B units were cancelled. For the year ended December 31, 2016, the Partnership incurred fees of approximately $0.9 million under the Management Agreement, which are included in General, administrative and other expense in the Partnership's consolidated statements of operations.

Related Parties	12 Months Ended Dec. 31, 2017
Related Party Transactions [Abstract]	
Related Party Transactions Disclosure [Text Block]	**Note 9. Related Parties**

Note 9. Related Parties

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

On December 18, 2015, the General Partner appointed Clifford J. Merritt as its President. Prior to being appointed President, Mr. Merritt provided consulting services to the Partnership. For the years ended December 31, 2017 and 2016, Mr. Merritt was paid $336,588 and $338,396, respectively, by the Partnership. Effective February 1, 2018, the General Partner agreed to increase Mr. Merritt's base compensation to $400,000, plus benefits.

On July 1, 2016, the Partnership entered into a one-year lease agreement with an affiliate of the General Partner for office space in Oklahoma City, Oklahoma. Under the terms of the agreement, the Partnership made twelve monthly payments of $8,537. The terms of the agreement continued on a month-to-month basis at the same monthly rate for the remainder of 2017, and will continue on a month-to-month basis at the same monthly rate into 2018. For the years ended December 31, 2017 and 2016, the Partnership paid $102,444 and $51,222, respectively, to the affiliate of the General Partner.

For the years ended December 31, 2017 and 2016, approximately $320,000 and $285,000 of general and administrative costs were incurred by a member of the General Partner and have been or will be reimbursed by the Partnership. At December 31, 2017, approximately $78,000 was due to a member of the General Partner.

The members of the General Partner are affiliates of Glade M. Knight, Chairman and Chief Executive Officer, David S. McKenney, Chief Financial Officer, Anthony F. Keating, III, Co-Chief Operating Officer and Michael J. Mallick, Co-Chief Operating Officer. Mr. Knight and Mr. McKenney are also the Chief Executive Officer and Chief Financial Officer of Energy Resources 12 GP, LLC, the general partner of Energy Resources 12, L.P. ("ER12"), 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 ER12 that will give ER12 access to the Partnership's personnel and administrative resources, including accounting, asset management and other day-to-day management support. See Note 11. Subsequent Events for additional information on this agreement.

In November 2017, ER12 engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting ER12 through closing and post-closing on the purchase of certain oil and gas properties in North Dakota. REI is owned by entities that are controlled by Mr. Keating and Mr. Mallick and has engaged Mr. Merritt to support its operations.

E11 Incentive Holdings, LLC ("Incentive Holdings") was the owner of all Class B units outstanding (62,500) as of March 31, 2017. During the second quarter of 2017, Incentive Holdings transferred substantially all of its assets; on April 5, 2017, Incentive Holdings transferred 18,125 of the 62,500 Class B units to E11 Incentive Carry Vehicle, LLC, an affiliate of Incentive Holdings, for de minimis consideration. On April 6, 2017, the remaining 44,375 Class B units were acquired by Regional Energy Incentives, LP in exchange for approximately $98,000. Regional Energy Incentives, LP is owned by entities that are controlled by Mr. Keating, Mr. Mallick and Mr. McKenney. The Class B units entitle the holder to certain distribution rights after Payout, as described in Note 7. Capital Contribution and Partners' Equity.

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)	12 Months Ended
	Dec. 31, 2017
Oil and Gas Exploration and Production Industries Disclosures [Abstract]	
Oil and Gas Exploration and Production Industries Disclosures [Text Block]	(see below)

Note 10. Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of oil, natural gas and NGL properties and related accumulated depreciation, depletion and amortization as of December 31, 2017 and 2016 is as follows:

	2017	2016
Producing properties	$ 186,647,918	$ 94,199,024
Non-producing	160,052,888	67,264,748
	346,700,806	161,463,772
Accumulated depreciation, depletion and amortization	(24,934,190)	(9,908,800)
Net capitalized costs	$ 321,766,616	$ 151,554,972

Costs Incurred

For the years ended December 31, 2017 and 2016, the Partnership incurred the following costs in oil and natural gas producing activities:

	2017	2016
Property acquisition costs	$ 180,957,486	$ 524,175
Development costs	4,279,548	1,652,782
	$ 185,237,034	$ 2,176,957

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, 2017, 2016 and 2015.

The Partnership's net proved oil, NGL and natural gas reserves, all of which are located in the contiguous United States, as of December 31, 2017, 2016 and 2015, have been estimated by the Partnership's independent consulting petroleum engineering firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate. Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available. "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)**
December 31, 2015	9,067,315	7,687,410	1,863,934	12,212,484
Acquisition	-	-	-	-
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (1)	222,321	2,799,032	(576,645)	112,182
Production	(498,926)	(519,122)	(69,059)	(654,506)
December 31, 2016	8,790,710	9,967,320	1,218,230	11,670,160
Acquisition (2)	13,192,588	14,885,856	1,819,384	17,492,948
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (3)	(3,434,686)	(3,691,027)	659,326	(3,390,531)
Production	(756,470)	(936,818)	(161,845)	(1,074,451)
December 31, 2017	17,792,142	20,225,331	3,535,095	24,698,126

(1) Revisions to previous estimates increased proved reserves by a net amount of 112 MBOE. These revisions resulted from 800 MBOE of upward adjustments attributable to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule, 124 MBOE of downward adjustments related to well performance and 217 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2016 to December 31, 2015.

Revisions of previous estimates for total proved reserves from December 31, 2015 to December 31, 2016 of 112 MBOE (increase) were less than revisions of previous estimates for proved undeveloped reserves for the same period of 442 MBOE (increase), primarily due to the incremental downward adjustment revisions to the proved developed reserves caused by changes in lower oil, natural gas and NGL prices (206 MBOE) and well performance (124 MBOE).

(2) The Partnership acquired 11,670 MBOE and 5,823 MBOE of producing developed wells and PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 17,493 MBOE during the year ended December 31, 2017.

(3) Revisions to previous estimates decreased proved reserves by a net amount of 3,391 MBOE. These revisions result from 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule and 1,213 MBOE of downward adjustments related to well performance, which were partially offset by 690 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2017 to December 31, 2016.

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, 2017 were $51.34 per barrel of oil and $2.98 per MMcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2017 were $44.84 per barrel of oil, $0.12 per MMcf of natural gas and $16.94 per barrel of NGL. The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2016 were $42.75 per barrel of oil and $2.48 per Mcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2016 were $36.25 per barrel of oil, ($0.38) per Mcf of natural gas and $4.70 per barrel of NGL. The gathering and processing contract in effect for the extraction, transportation and treatment of natural gas led to a price differential that exceeded the twelve-month average market price for natural gas, which results in an estimated negative average realized natural gas price utilized in the December 31, 2016 reserves calculation.

	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
Proved developed reserves:				
December 31, 2016	4,748,350	5,163,240	631,080	6,239,970
December 31, 2017	9,640,723	11,300,071	1,975,089	13,499,157
Proved undeveloped reserves:				
December 31, 2016	4,042,360	4,804,080	587,150	5,430,190
December 31, 2017	8,151,419	8,925,260	1,560,006	11,198,968

The following details the changes in proved undeveloped reserves for 2016 and 2017:

	BOE
Proved undeveloped reserves, December 31, 2015	4,988,274
Revisions of previous estimates (1)	441,916
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430,190
Revisions of previous estimates (2)	(2,838,164)
Conversion to proved developed reserves (3)	(518,686)
Proved undeveloped reserves acquired (4)	9,125,628
Proved undeveloped reserves, December 31, 2017	11,198,968

(1) The annual review of the PUDs resulted in a positive revision of approximately 442 MBOE. This revision was a result of 800 MBOE of upward adjustments related to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule and 11 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the December 31, 2016 reserve estimates to prices used in the December 31, 2015 reserve estimates. There were no adjustments related to well performance.

(2) The annual review of the PUDs resulted in a negative revision of approximately 2,838 MBOE. This revision was the result of 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule, which were partially offset by 30 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the December 31, 2017 reserve estimates to prices used in the December 31, 2016 reserve estimates. There were no adjustments related to well performance.

(3) The Partnership is participating in the drilling and completion of six wells, which are in progress at December 31, 2017 (see Note 3. Oil and Gas Investments) and represent a conversion of 519 MBOE from the PUD category to proved developed for the year ended December 31, 2017.

(4) The Partnership acquired 5,430 MBOE and 3,696 MBOE of PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 9,126 MBOE during the year ended December 31, 2017.

Although the Partnership has performed limited drilling since acquisition, 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 will be removed as revisions at the time that determination is 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.

	2017	2016
Future cash inflows	$ 860,125,991	$ 320,606,188
Future production costs	(292,788,015)	(122,527,901)
Future development costs	(96,111,664)	(43,050,408)
Future net cash flows	471,226,312	155,027,879
10% annual discount	(285,321,062)	(94,081,952)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

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

	2017	2016
Standardized measure at beginning of period	$ 60,945,927	$ 99,189,842
Changes resulting from:		
Acquisition of reserves	97,630,985	524,175
Sales of oil, natural gas and NGLs, net of production costs	(25,571,593)	(12,684,015)
Net changes in prices and production costs	85,222,533	(28,508,492)
Development costs incurred during the period	4,279,548	1,652,782
Revisions to previous estimates	(57,488,282)	(3,750,720)
Accretion of discount	6,103,044	9,932,739
Change in estimated future development costs	14,783,088	(5,410,384)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

Quarterly Financial Data (Unaudited)	12 Months Ended Dec. 31, 2017
Quarterly Financial Information Disclosure [Abstract]	
Quarterly Financial Information [Text Block]	**Note 11. Quarterly Financial Data (Unaudited)**

The following is a summary of quarterly results of operations for the years ended December 31, 2017 and 2016. 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.

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 10,141,266	$ 10,208,740	$ 9,717,996	$ 10,944,738
Net income	$ 2,621,071	$ 1,986,404	$ 1,280,559	$ 2,008,288
Basic and diluted net income per common share	$ 0.17	$ 0.11	$ 0.07	$ 0.11

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 4,319,097	$ 5,532,113	$ 5,434,047	$ 5,080,081
Net income (loss)	$ (3,592,456)	$ (859,383)	$ (1,511,146)	$ 732,421
Basic and diluted net income (loss) per common share	$ (0.73)	$ (0.14)	$ (0.20)	$ 0.06

Subsequent Events	12 Months Ended Dec. 31, 2017
Subsequent Events [Abstract]	
Subsequent Events [Text Block]	**Note 12. Subsequent Events** In January 2018, the Partnership declared and paid $1.7 million, or $0.092055 per outstanding common unit, in distributions to its holders of common units. On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy Resources 12, L.P. that will give Energy Resources 12, L.P. access to the Partnership's personnel and administrative resources, including accounting, asset management and other day-to-day management support. The shared day-to-day costs will be split evenly between the two partnerships and any direct third-party costs will be paid by the party receiving the services. The shared costs will be based on actual costs incurred with no mark-up or profit to the Partnership. The agreement may be terminated at any time by either party upon 60 days written notice. The chief executive officer and chief financial officer of the Partnership's General Partner are also chief executive officer and chief financial officer of the general partner of Energy Resources 12, L.P. In February 2018, the Partnership declared and paid $1.7 million, or $0.092055 per outstanding common unit, in distributions to its holders of common units.

Accounting Policies, by Policy (Policies)	12 Months Ended Dec. 31, 2017
Accounting Policies [Abstract]	
Basis of Accounting, Policy [Policy Text Block]	*Basis of Presentation* The accompanying consolidated 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.
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 our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates 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, 2017, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2017, the Partnership's oil, natural gas and NGL sales were through two operators. Whiting Petroleum Corporation ("Whiting") is the operator of 99% of the Partnership's properties. 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]	*Asset Retirement Obligation* 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 years ended December 31, 2017 and 2016, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2015	$ 105,459
Well additions	1,868
Accretion	9,689
Revisions in estimated cash flows	(46,393)
Balance as of December 31, 2016	70,623
Liabilities incurred on January 11, 2017 (acquisition)	781,628
Liabilities incurred on March 31, 2017 (acquisition)	289,827
Well additions	22,582
Accretion	59,114
Revisions in estimated cash flows	3,105
Balance as of December 31, 2017	$ 1,226,879

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.
Industry Specific Policies, Oil and Gas [Policy Text Block]	*Oil, NGL and Natural Gas Sales and Natural Gas Imbalances* The Partnership follows the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where the Partnership has taken less than its share of production.

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, 2017 and 2016, there were no such costs accrued.
Use of Estimates, Policy [Policy Text Block]	*Use of Estimates* Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates. Of these estimates and assumptions, management considers the estimation of 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 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* Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.
Reclassification, Policy [Policy Text Block]	*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.
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 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, 2017 and 2016. As a result, basic and diluted outstanding common units were the same. The Class B Units and Incentive Distribution Rights 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 January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2017-01, Business Combinations (Topic 805), which amends the existing accounting standards to clarify the definition of a business and assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, including interim periods within those periods, and should be applied prospectively on or after the effective date. Early application is permitted for transactions that occur before the issuance or effective date of this amendment, provided the transaction has not been reported in financial statements that have been issued or made available for issuance. The Partnership adopted the standard effective January 1, 2017. The Partnership's acquisitions prior to 2017 were accounted for as acquisitions of an existing business and therefore, all transaction costs were expensed as incurred. The Partnership's acquisitions in the first quarter of 2017 were accounted for as asset purchases with acquisition costs, such as legal, title and accounting costs, being capitalized as part of the cost of the assets acquired. The Partnership will evaluate any future acquisition(s) of oil and gas properties under the revised standard and account for the acquisition as either an asset purchase or business combination depending on the particular facts and circumstances of the acquisition.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, that amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. Throughout 2016 and 2017, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 2017-14, respectively, to clarify specific topics originally described in ASU 2014-09. In August 2015, the FASB issued ASU No. 2015-14, which deferred the effective date of ASU 2014-09 to annual and interim periods beginning after December 15, 2017, and permitted early application for annual reporting periods beginning after December 15, 2016. The Partnership adopted this standard on January 1, 2018 using the modified retrospective approach. Based on its assessment of this standard, the Partnership does not believe the standard will have a significant change to the amount or timing of the recording of revenue in its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the existing accounting standards for lease accounting, including requiring lessees to recognize most leases on their balance sheets as right-of-use assets and lease liabilities. The standard is effective for annual and interim periods beginning after December 15, 2018 with early adoption permitted. The Partnership expects to adopt this standard as of January 1, 2019. The Partnership is still evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

Summary of Significant Accounting Policies (Tables)	12 Months Ended Dec. 31, 2017
Accounting Policies [Abstract]	
Schedule of Asset Retirement Obligations [Table Text Block]	The following table shows the activity for the years ended December 31, 2017 and 2016, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2015	$	105,459
Well additions		1,868
Accretion		9,689
Revisions in estimated cash flows		(46,393)
Balance as of December 31, 2016		70,623
Liabilities incurred on January 11, 2017 (acquisition)		781,628
Liabilities incurred on March 31, 2017 (acquisition)		289,827
Well additions		22,582
Accretion		59,114
Revisions in estimated cash flows		3,105
Balance as of December 31, 2017	$	1,226,879

Oil and Gas Investments (Tables)	12 Months Ended Dec. 31, 2017
Oil and Gas Property [Abstract]	
Business Acquisition, Pro Forma Information [Table Text Block]	The following unaudited pro forma financial information for the years ended December 31, 2017 and 2016 have been prepared as if Acquisitions No. 2 and No. 3 of the Sanish Field Assets had occurred on January 1, 2016. The unaudited pro forma financial information was derived from the historical Statements of Operations of the Partnership and the historical information provided by the sellers. The unaudited pro forma financial information does not purport to be indicative of the results of operations that would have occurred had the acquisitions of the Sanish Field Assets and related financings occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

	Year Ended December 31, 2017	Year Ended December 31, 2016
	(Unaudited)	(Unaudited)
Revenues	$ 43,355,472	$ 47,506,576
Net income	$ 7,957,922	$ 384,443

Fair Value of Financial Instruments (Tables)	12 Months Ended Dec. 31, 2017
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, 2017.

Fair Value Measurements at December 31, 2017		
Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs

	(Level 1)		(Level 2)		(Level 3)
Commodity derivatives - current assets	$	-	$	-	$	-
Commodity derivatives - current liabilities		-		(1,026,965)		-
Total	$	-	$	(1,026,965)	$	-

Risk Management (Tables)	12 Months Ended Dec. 31, 2017
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Schedule of Derivative Instruments [Table Text Block]	All of 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.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)	Fair Value of Asset / (Liability) at December 31, 2017
01/01/18 - 12/31/18	NYMEX	294,000	$ 52.00 / 57.05	$ (1,011,684)
01/01/18 - 12/31/18	NYMEX	36,000	$ 55.00 / 61.35	(15,281)
				$ (1,026,965)

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Tables)	12 Months Ended Dec. 31, 2017
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 and related accumulated depreciation, depletion and amortization as of December 31, 2017 and 2016 is as follows:

	2017	2016
Producing properties	$ 186,647,918	$ 94,199,024
Non-producing	160,052,888	67,264,748
	346,700,806	161,463,772
Accumulated depreciation, depletion and amortization	(24,934,190)	(9,908,800)
Net capitalized costs	$ 321,766,616	$ 151,554,972

Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure [Table Text Block]

For the years ended December 31, 2017 and 2016, the Partnership incurred the following costs in oil and natural gas producing activities:

	2017	2016
Property acquisition costs	$ 180,957,486	$ 524,175
Development costs	4,279,548	1,652,782
	$ 185,237,034	$ 2,176,957

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)
December 31, 2015	9,067,315	7,687,410	1,863,934	12,212,484
Acquisition	-	-	-	-
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (1)	222,321	2,799,032	(576,645)	112,182
Production	(498,926)	(519,122)	(69,059)	(654,506)
December 31, 2016	8,790,710	9,967,320	1,218,230	11,670,160
Acquisition (2)	13,192,588	14,885,856	1,819,384	17,492,948
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (3)	(3,434,686)	(3,691,027)	659,326	(3,390,531)
Production	(756,470)	(936,818)	(161,845)	(1,074,451)
December 31, 2017	17,792,142	20,225,331	3,535,095	24,698,126

	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
Proved developed reserves:				
December 31, 2016	4,748,350	5,163,240	631,080	6,239,970
December 31, 2017	9,640,723	11,300,071	1,975,089	13,499,157
Proved undeveloped reserves:				
December 31, 2016	4,042,360	4,804,080	587,150	5,430,190
December 31, 2017	8,151,419	8,925,260	1,560,006	11,198,968

	BOE
Proved undeveloped reserves, December 31, 2015	4,988,274
Revisions of previous estimates (1)	441,916
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430,190
Revisions of previous estimates (2)	(2,838,164)
Conversion to proved developed reserves (3)	(518,686)
Proved undeveloped reserves acquired (4)	9,125,628
Proved undeveloped reserves, December 31, 2017	11,198,968

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.

	2017	2016
Future cash inflows	$ 860,125,991	$ 320,606,188
Future production costs	(292,788,015)	(122,527,901)
Future development costs	(96,111,664)	(43,050,408)
Future net cash flows	471,226,312	155,027,879
10% annual discount	(285,321,062)	(94,081,952)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

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:

	2017	2016
Standardized measure at beginning of period	$ 60,945,927	$ 99,189,842
Changes resulting from:		
Acquisition of reserves	97,630,985	524,175
Sales of oil, natural gas and NGLs, net of production costs	(25,571,593)	(12,684,015)
Net changes in prices and production costs	85,222,533	(28,508,492)
Development costs incurred during the period	4,279,548	1,652,782
Revisions to previous estimates	(57,488,282)	(3,750,720)
Accretion of discount	6,103,044	9,932,739
Change in estimated future development costs	14,783,088	(5,410,384)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

Quarterly Financial Data (Unaudited) (Tables)	12 Months Ended Dec. 31, 2017
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, 2017 and 2016. 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.

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 10,141,266	$ 10,208,740	$ 9,717,996	$ 10,944,738
Net income	$ 2,621,071	$ 1,986,404	$ 1,280,559	$ 2,008,288
Basic and diluted net income per common share	$ 0.17	$ 0.11	$ 0.07	$ 0.11
	2016			

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 4,319,097	$ 5,532,113	$ 5,434,047	$ 5,080,081
Net income (loss)	$ (3,592,456)	$ (859,383)	$ (1,511,146)	$ 732,421
Basic and diluted net income (loss) per common share	$ (0.73)	$ (0.14)	$ (0.20)	$ 0.06

Partnership Organization (Details) shares in Millions		12 Months Ended		46 Months Ended
	Jul. 09, 2013 USD ($)	Dec. 31, 2017 USD ($)	Dec. 31, 2016 USD ($)	Apr. 24, 2017 USD ($) shares
Partnership Organization (Details) [Line Items]				
Limited Liability Company or Limited Partnership, Business, Formation State	Delaware			
Partners' Capital Account, Contributions (in Dollars)	$ 1,000			
Proceeds from Issuance of Common Limited Partners Units (in Dollars)		$ 82,515,450	$ 188,820,033	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units (in Dollars)		$ 82,510,325	$ 188,825,158	
Sanish Field Located in Mountrail County, North Dakota [Member]				
Partnership Organization (Details) [Line Items]				
Productive Oil Wells, Number of Wells, Net		215		
Wells in Process of Drilling		6		
Gas and Oil Area Undeveloped, Net		247		
Minimum [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]				
Partnership Organization (Details) [Line Items]				
Gas and Oil Area Developed, Net		26.00%		
Maximum [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]				
Partnership Organization (Details) [Line Items]				
Gas and Oil Area Developed, Net		27.00%		
Best-Efforts Offering [Member]				
Partnership Organization (Details) [Line Items]				
Partners' Capital Account, Units, Sale of Units (in Shares) | shares				19.0
Proceeds from Issuance of Common Limited Partners Units (in Dollars)				$ 374,200,000
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units (in Dollars)				$ 349,600,000

Summary of Significant Accounting Policies (Details)	12 Months Ended	
	Dec. 31, 2017 shares	Dec. 31, 2016 shares
Summary of Significant Accounting Policies (Details) [Line Items]		
Number of Operators	2	
Antidilutive Securities Excluded from Computation of Earnings Per Share, Amount	0	0
Sales Revenue, Net [Member] |		

Whiting Petroleum [Member] | Customer Concentration Risk [Member]		
Summary of Significant Accounting Policies (Details) [Line Items]		
Concentration Risk, Percentage	99.00%	

Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations - USD ($)	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations [Line Items]		
Balance	$ 70,623	$ 105,459
Well additions	22,582	1,868
Accretion	59,114	9,689
Revisions in estimated cash flows	3,105	(46,393)
Balance	1,226,879	$ 70,623
Acquisition No. 2 [Member]		
Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations [Line Items]		
Well additions	781,628	
Acquisition No. 3 [Member]		
Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations [Line Items]		
Well additions	$ 289,827	

Oil and Gas Investments (Details)				1 Months Ended	12 Months Ended		
	Mar. 31, 2017 USD ($)	Jan. 11, 2017 USD ($)	Dec. 18, 2015 USD ($)	Mar. 31, 2017 USD ($)	Dec. 31, 2017 USD ($)	Dec. 31, 2016 USD ($)	Nov. 30, 2017
Oil and Gas Investments (Details) [Line Items]							
Asset Retirement Obligation, Liabilities Incurred (in Dollars)					$ 22,582	$ 1,868	
Costs Incurred, Development Costs (in Dollars)					$ 4,279,548	$ 1,652,782	
Sanish Field Located in Mountrail County, North Dakota [Member]							
Oil and Gas Investments (Details) [Line Items]							
Productive Oil Wells, Number of Wells, Net					215		
Gas and Oil Area Undeveloped, Net					247		
Wells in Process of Drilling					6		
Estimated Capital Expenditures, Drilling and Completion of Wells (in Dollars)					$ 7,000,000		
Costs Incurred, Development Costs (in Dollars)					$ 1,300,000		
Sanish Field Located in Mountrail County, North Dakota [Member] | Whiting Petroleum [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest							29.00%
Wells in Process of Drilling							2
Sanish Field Located in Mountrail County, North Dakota [Member] | Minimum [Member]							
Oil and Gas Investments (Details)							

[Line Items]							
Gas and Oil Area Developed, Net					26.00%		
Working Interest					26.00%		
Sanish Field Located in Mountrail County, North Dakota [Member] | Maximum [Member]							
Oil and Gas Investments (Details) [Line Items]							
Gas and Oil Area Developed, Net					27.00%		
Working Interest					27.00%		
Acquisition No. 1 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]							
Oil and Gas Investments (Details) [Line Items]							
Gas and Oil Area Developed, Net			11.00%				
Business Combination, Consideration Transferred (in Dollars)			$ 159,600,000				
Acquisition No. 2 [Member]							
Oil and Gas Investments (Details) [Line Items]							
Asset Retirement Obligation, Liabilities Incurred (in Dollars)					$ 781,628		
Acquisition No. 2 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]							
Oil and Gas Investments (Details) [Line Items]							
Gas and Oil Area Developed, Net		11.00%					
Business Combination, Consideration Transferred (in Dollars)		$ 128,500,000					
Debt Instrument, Face Amount (in Dollars)		40,000,000					
Acquisition Costs, Period Cost (in Dollars)					43,000		
Asset Retirement Obligation, Liabilities Incurred (in Dollars)		$ 800,000					
Acquisition No. 2 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member] | Minimum [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest		22.00%					
Acquisition No. 2 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member] | Maximum [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest		23.00%					
Acquisition No. 3 [Member]							
Oil and Gas Investments (Details) [Line Items]							
Asset Retirement Obligation, Liabilities Incurred (in Dollars)					289,827		
Acquisition No. 3 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]							
Oil and Gas Investments (Details) [Line Items]							
Gas and Oil Area Developed, Net	10.50%						

Business Combination, Consideration Transferred (in Dollars)				$ 52,400,000			
Debt Instrument, Face Amount (in Dollars)	$ 33,000,000			$ 33,000,000			
Acquisition Costs, Period Cost (in Dollars)					$ 80,000		
Asset Retirement Obligation, Liabilities Incurred (in Dollars)	$ 300,000						
Number of Producing Partnership Wells Acquired	82						
Productive Oil Wells, Number of Wells, Net	216			216			
Number of Future Development Partnership Locations Acquired	150						
Gas and Oil Area Undeveloped, Net	253						
Acquisition No. 3 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member] | Minimum [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest	26.00%			26.00%			
Acquisition No. 3 [Member] | Sanish Field Located in Mountrail County, North Dakota [Member] | Maximum [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest	27.00%			27.00%			
Sanish Field Located in Mountrail County, North Dakota [Member]							
Oil and Gas Investments (Details) [Line Items]							
Wells in Process of Drilling							6
Sanish Field Located in Mountrail County, North Dakota [Member] | Oasis Petroleum, Inc. [Member]							
Oil and Gas Investments (Details) [Line Items]							
Wells in Process of Drilling							4
Sanish Field Located in Mountrail County, North Dakota [Member] | Minimum [Member] | Oasis Petroleum, Inc. [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest							7.00%
Sanish Field Located in Mountrail County, North Dakota [Member] | Maximum [Member] | Oasis Petroleum, Inc. [Member]							
Oil and Gas Investments (Details) [Line Items]							
Working Interest							9.00%

Oil and Gas Investments (Details) - Business Acquisition, Pro Forma Information - USD ($)	**12 Months Ended**	
	Dec. 31, 2017	**Dec. 31, 2016**
Business Acquisition, Pro Forma Information [Abstract]		
Revenues	$ 43,355,472	$ 47,506,576
Net income	$ 7,957,922	$ 384,443

Debt (Details) - USD ($)					1 Months Ended	3 Months Ended	12 Months Ended			
	Nov. 21, 2017	Mar. 31, 2017	Feb. 23, 2017	Jan. 11, 2017	Jul. 31, 2017	Sep. 30, 2016	Dec. 31, 2017	Dec. 31, 2016	Jun. 30, 2016	Dec. 18, 2015
Debt (Details) [Line Items]										
Repayments of Debt							$ 72,707,356	$ 88,917,833		
Proceeds from Lines of Credit							20,000,000	0		
Long-term Line of Credit							20,000,000	$ 0		
Lines of Credit, Fair Value Disclosure							20,000,000			
Revolving Credit Facility [Member]										
Debt (Details) [Line Items]										
Debt Instrument, Face Amount	$ 20,000,000									
Repayments of Debt							$ 5,900,000			
Line of Credit Facility, Borrowing Capacity, Description	The commitment amount may be increased up to $75 million									
Line of Credit Facility, Commitment Fee Percentage	0.30%									
Line of Credit Facility, Commitment Fee Amount	$ 60,000									
Line of Credit Facility, Commitment Fee in Excess of Revolver Amount, Percentage	0.30%									
Line of Credit Facility, Unused Capacity, Commitment Fee Percentage	0.50%									
Line of Credit Facility, Maximum Borrowing Capacity	$ 30,000,000									
Long-term Debt, Percentage Bearing Variable Interest, Percentage Rate							4.76%			
Proceeds from Lines of Credit							$ 20,000,000			
Payments to Acquire Businesses, Gross							$ 1,000,000			
Wells in Process of Drilling							6			
Line of Credit Facility, Collateral	The Credit Facility is secured by a mortgage and first lien position on at least 80% of the Partnership's producing wells.									
Line of Credit Facility, Covenant Terms	The Credit Facility contains mandatory prepayment requirements, customary affirmative and negative covenants and events of default. The financial covenants 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, 2017.			
Notes Payable, Other Payables [Member]										

Debt (Details) [Line Items]										
Debt Instrument, Face Amount										$ 97,500,000
Debt Instrument, Increase (Decrease) for Period, Description								On June 23, 2016, Seller Note 1 was increased by $5.0 million to satisfy the contingent payment due to the sellers as defined in the First Amendment of the Interest Purchase Agreement. The Partnership was given the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to satisfy the contingent payment in full by paying to the sellers $5.0 million at the time of election or by increasing the amount of Seller Note 1 by $5.0 million.		
Debt Instrument, Description								On June 23, 2016, the Partnership exercised that right by increasing the amount of Seller Note 1 by $5.0 million. If the Partnership had not exercised the one-time right, the contingent payment would have ranged from $0 to $95 million depending on the average of the monthly NYMEX:CL strip prices as of December 31, 2017 for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022.		
Debt Instrument, Increase (Decrease), Net								$ 5,000,000		
Debt Instrument, Fee								in accordance with Seller Note 1, because the Partnership had not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership paid a		

								deferred origination fee equal to $250,000 during the three months ended June 30, 2016.		
Amortization of Deferred Loan Origination Fees, Net						$ (250,000)				
Debt Instrument, Fee Amount									$ 250,000	
Minimum [Member] | Revolving Credit Facility [Member] | London Interbank Offered Rate (LIBOR) [Member]										
Debt (Details) [Line Items]										
Debt Instrument, Basis Spread on Variable Rate	2.50%									
Maximum [Member] | Revolving Credit Facility [Member] | London Interbank Offered Rate (LIBOR) [Member]										
Debt (Details) [Line Items]										
Debt Instrument, Basis Spread on Variable Rate	3.50%									
Acquisition No. 2 [Member] | Notes Payable, Other Payables [Member]										
Debt (Details) [Line Items]										
Repayments of Debt			$ 40,000,000							
Debt Instrument, Outstanding Balance				$ 40,000,000						
Debt Instrument, Interest Rate, Stated Percentage				5.00%						
Debt Instrument, Maturity Date				Feb. 23, 2017						
Acquisition No. 3 [Member] | Notes Payable, Other Payables [Member]										
Debt (Details) [Line Items]										
Debt Instrument, Face Amount		$ 33,000,000								
Repayments of Debt	$ 5,900,000				$ 2,000,000					
Debt Instrument, Interest Rate, Stated Percentage		5.00%								
Debt Instrument, Maturity Date		Aug. 01, 2017			Jun. 29, 2018					
Debt Instrument, Periodic Payment					$ 2,000,000					

Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis - USD ($)	Dec. 31, 2017	Dec. 31, 2016
Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Line Items]		
Commodity derivatives - current liabilities	$ (1,026,965)	$ 0
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	
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	0	

Commodity derivatives - current liabilities	(1,026,965)	
Total	(1,026,965)	
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	
Total	$ 0	

Risk Management (Details) - USD ($)	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Derivative Instruments and Hedging Activities Disclosure [Abstract]		
Derivative Liability	$ 1,000,000	
Derivative, Gain (Loss) on Derivative, Net	$ (1,026,965)	$ 0

Risk Management (Details) - Schedule of Derivative Instruments	12 Months Ended
	Dec. 31, 2017 USD ($) $ / item bbl
Derivative [Line Items]	
Fair Value of Asset (Liability) (in Dollars) | $	$ (1,026,965)
Price Risk Derivative [Member] | 01/01/18 - 12/31/18 [Member]	
Derivative [Line Items]	
Basis	NYMEX
Oil (Barrels) (in Barrels (of Oil)) | bbl	294,000
Floor Price	52.00
Ceiling Price	57.05
Fair Value of Asset (Liability) (in Dollars) | $	$ (1,011,684)
Price Risk Derivative [Member] | 01/01/18 - 12/31/18 [Member]	
Derivative [Line Items]	
Basis	NYMEX
Oil (Barrels) (in Barrels (of Oil)) | bbl	36,000
Floor Price	55.00
Ceiling Price	61.35
Fair Value of Asset (Liability) (in Dollars) | $	$ (15,281)

Capital Contribution and Partners' Equity (Details) - USD ($) $ / shares in Units, shares in Millions			12 Months Ended		46 Months Ended
	Nov. 29, 2017	Jul. 09, 2013	Dec. 31, 2017	Dec. 31, 2016	Apr. 24, 2017
Capital Contribution and Partners' Equity (Details) [Line Items]					
Partners' Capital Account, Contributions		$ 1,000			
Distributions to organizational limited partner		$ 990			
Proceeds from Issuance of Common Limited Partners Units			$ 82,515,450	$ 188,820,033	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units			$ 82,510,325	$ 188,825,158	

Managing Dealer, Selling Commissions, Percentage			6.00%		
Managing Dealer, Maximum Contingent Incentive Fee on Gross Proceeds, Percentage			4.00%		
Maximum Contingent Offering Costs, Selling Commissions and Marketing Expenses			$ 15,000,000		
Key Provisions of Operating or Partnership Agreement, Description			The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines “Payout Accrual” as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership’s assets, will be made as follows:·First, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;·Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest (currently 43.125%). The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed below.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)			$ 1.361643	$ 1.400000	
Distribution Made to Limited Partner, Cash Distributions Paid			$ 24,578,224	$ 10,448,981	
Distribution Made to Limited Partner, Distribution Rate	6.00%			7.00%	
Partners Capital Account, Units Sold, Price Per Unit	$ 20.00				
Distribution at Payout to limited partner, per common unit (in Dollars per share)			$ 0.034521		
Distribution at Payout to limited partner			$ 700,000		
Best-Efforts Offering [Member]					
Capital Contribution and Partners' Equity (Details) [Line Items]					
Partners' Capital Account, Units, Sale of Units (in Shares)					19.0
Proceeds from Issuance of Common Limited Partners Units					$ 374,200,000
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units					$ 349,600,000

Management Agreement (Details) $ in Millions	12 Months Ended
	Dec. 31, 2016 USD ($) shares
Management Agreement (Details) [Line Items]	
Owned Property, Reimbursable Management Costs (in Dollars) | $	$ 0.9
E11 Incentive Holdings [Member]	

Management Agreement (Details) [Line Items]	
Class B Units Issued to Manager	100,000
Class B Units, Cancelled	37,500

Related Parties (Details) - USD ($)					12 Months Ended		
	Feb. 01, 2018	Apr. 06, 2017	Apr. 05, 2017	Jul. 01, 2016	Dec. 31, 2017	Dec. 31, 2016	Mar. 31, 2017
Related Parties (Details) [Line Items]							
Class B Units, Units Outstanding (in Shares)					62,500	62,500	
E11 Incentive Holdings [Member]							
Related Parties (Details) [Line Items]							
Class B Units, Units Outstanding (in Shares)							62,500
Units transferred to E11 Incentive Carry Vehicle, LP for minimis Consideration [Member] | E11 Incentive Holdings [Member]							
Related Parties (Details) [Line Items]							
Class B Units, transferred (in Shares)			18,125				
Units Sold to Regional Energy Incentives, LP [Member] | E11 Incentive Holdings [Member]							
Related Parties (Details) [Line Items]							
Class B Units, Units Sold (in Shares)		44,375					
Class B Units, Total Sales Price for Sale of Capital Units		$ 98,000					
Affiliated Entity [Member]							
Related Parties (Details) [Line Items]							
Operating Leases, Rent Expense, Minimum Rentals				$ 8,537			
Operating Leases, Rent Expense					$ 102,444	$ 51,222	
General Partner [Member]							
Related Parties (Details) [Line Items]							
Related Party Transaction, Selling, General and Administrative Expenses from Transactions with Related Party					320,000	285,000	
Due to Related Parties, Current					78,000		
Consulting Services Provided to General Partner [Member] | President [Member]							
Related Parties (Details) [Line Items]							
Costs and Expenses, Related Party					$ 336,588	$ 338,396	
Subsequent Event [Member] | President [Member]							
Related Parties (Details) [Line Items]							
Officer, Base Compensation	$ 400,000						

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details)	12 Months Ended			
	Dec. 31, 2017 Boe $ / bbl $ / MMcf		Dec. 31, 2016 Boe $ / bbl $ / MMcf	
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)	(2,838,164)	[1]	441,916	[2]

Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	9,125,628	[3]	0	
Proved Developed and Undeveloped Reserve, Net (Energy), Period Increase (Decrease)	(518,686)	[4]	0	
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)	(3,391,000)		112,000	
Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	17,493,000			
Proved Reserves [Member] | Adjustments for the addition of Wells [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)			800,000	
Wells, Addition of Proved Undeveloped Drilling Locations			9	
Proved Reserves [Member] | Adjustment 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)	(2,868,000)		(347,000)	
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)	(1,213,000)		(124,000)	
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)	690,000		(217,000)	
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)	(2,838,000)		442,000	
Proved Developed and Undeveloped Reserve, Purchase of Mineral in Place (Energy)	9,126,000			
Wells in Process of Drilling	6			
Proved Developed and Undeveloped Reserve, Net (Energy), Period Increase (Decrease)	519,000			
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)	30,000		11,000	
Proved Developed 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)			124,000	
Proved Developed 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)			206,000	
Oil [Member] | Before Price Differentials [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	51.34		42.75	
Oil [Member] | Including Effect of Price Differential Adjustments [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	44.84		36.25	
Natural Gas [Member] | Before Price Differentials [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)) | $ / MMcf	2.98		2.48	
Natural Gas [Member] | Including Effect of Price Differential				

Adjustments [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)) | $ / MMcf	0.12		(0.38)	
Natural Gas Liquids [Member] | Including Effect of Price Differential Adjustments [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	16.94		4.70	
Acquisition No. 2 [Member] | Proved Reserves [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)	11,670,000			
Acquisition No. 2 [Member] | Proved Undeveloped Reserves [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)	5,430,000			
Acquisition No. 3 [Member] | Proved Reserves [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)	5,823,000			
Acquisition No. 3 [Member] | Proved Undeveloped Reserves [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)	3,696,000			

[1] The annual review of the PUDs resulted in a negative revision of approximately 2,838 MBOE. This revision was the result of 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule, which were partially offset by 30 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the December 31, 2017 reserve estimates to prices used in the December 31, 2016 reserve estimates. There were no adjustments related to well performance.

[2] The annual review of the PUDs resulted in a positive revision of approximately 442 MBOE. This revision was a result of 800 MBOE of upward adjustments related to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule and 11 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the December 31, 2016 reserve estimates to prices used in the December 31, 2015 reserve estimates. There were no adjustments related to well performance.

[3] The Partnership acquired 5,430 MBOE and 3,696 MBOE of PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 9,126 MBOE during the year ended December 31, 2017.

[4] The Partnership is participating in the drilling and completion of six wells, which are in progress at December 31, 2017 (see Note 3. Oil and Gas Investments) and represent a conversion of 519 MBOE from the PUD category to proved developed for the year ended December 31, 2017.

Supplementary Information on Oil,		

Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Capitalized Costs Relating to Oil and Gas Producing Activities Disclosure - USD ($)	Dec. 31, 2017	Dec. 31, 2016
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]		
Proved Properties	$ 346,700,806	$ 161,463,772
Accumulated depreciation, depletion and amortization	(24,934,190)	(9,908,800)
Net capitalized costs	321,766,616	151,554,972
Producing Properties [Member]		
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]		
Proved Properties	186,647,918	94,199,024
Non-Producing Properties [Member]		
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]		
Proved Properties	$ 160,052,888	$ 67,264,748

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure - USD ($)	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure [Abstract]		
Property acquisition costs	$ 180,957,486	$ 524,175
Development costs	4,279,548	1,652,782
	$ 185,237,034	$ 2,176,957

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, 2017 Boe bbl Mcf		Dec. 31, 2016 Boe bbl Mcf		Dec. 31, 2015 Boe
Reserve Quantities [Line Items]					
Balance	11,670,160		12,212,484		
Balance, Proved Developed Reserves (in Barrels of Oil Equivalent) | Boe	13,499,157		6,239,970		
Balance, Proved Undeveloped Reserves (in Barrels of Oil Equivalent) | Boe	11,198,968		5,430,190		
Balance, Proved Undeveloped Reserves (in Barrels of Oil Equivalent) | Boe	11,198,968		4,988,274		5,430,190
Revisions of previous estimates (in Barrels of Oil Equivalent) | Boe	(2,838,164)	[1]	441,916	[2]	
Conversion to proved developed reserves (in Barrels of Oil Equivalent) | Boe	(518,686)	[3]	0		
Proved undeveloped reserves acquired (in Barrels of Oil Equivalent) | Boe	9,125,628	[4]	0		
Acquisition	17,492,948	[5]	0		
Extensions, discoveries and other additions	0		0		
		[6]		[7]	

Revisions of previous estimates	(3,390,531)		112,182		
Production	(1,074,451)		(654,506)		
Balance	24,698,126		11,670,160		
Oil [Member]					
Reserve Quantities [Line Items]					
Balance	8,790,710		9,067,315		
Balance, Proved Developed Reserves	9,640,723		4,748,350		
Balance, Proved Undeveloped Reserves	8,151,419		4,042,360		
Acquisition	13,192,588	[5]	0		
Extensions, discoveries and other additions	0		0		
Revisions of previous estimates	(3,434,686)	[6]	222,321	[7]	
Production	(756,470)		(498,926)		
Balance	17,792,142		8,790,710		
Natural Gas [Member]					
Reserve Quantities [Line Items]					
Balance | Mcf	9,967,320		7,687,410		
Balance, Proved Developed Reserves | Mcf	11,300,071		5,163,240		
Balance, Proved Undeveloped Reserves | Mcf	8,925,260		4,804,080		
Acquisition | Mcf	14,885,856	[5]	0		
Extensions, discoveries and other additions | Mcf	0		0		
Revisions of previous estimates | Mcf	(3,691,027)	[6]	2,799,032	[7]	
Production | Mcf	(936,818)		(519,122)		
Balance | Mcf	20,225,331		9,967,320		
Natural Gas Liquids [Member]					
Reserve Quantities [Line Items]					
Balance	1,218,230		1,863,934		
Balance, Proved Developed Reserves	1,975,089		631,080		
Balance, Proved Undeveloped Reserves	1,560,006		587,150		
Acquisition	1,819,384	[5]	0		
Extensions, discoveries and other additions	0		0		
Revisions of previous estimates	659,326	[6]	(576,645)	[7]	
Production	(161,845)		(69,059)		
Balance	3,535,095		1,218,230		

[1] The annual review of the PUDs resulted in a negative revision of approximately 2,838 MBOE. This revision was the result of 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule, which were partially offset by 30 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the December 31, 2017 reserve estimates to prices used in the December 31, 2016 reserve estimates. There were no adjustments related to well performance.

[2] The annual review of the PUDs resulted in a positive revision of approximately 442 MBOE. This revision was a result of 800 MBOE of upward adjustments related to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule and 11 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the December 31, 2016 reserve estimates to prices used in the December 31, 2015 reserve estimates. There were no adjustments related to well performance.

[3] The Partnership is participating in the drilling and completion of six wells, which are in progress at December 31, 2017 (see Note 3. Oil and Gas Investments) and represent a conversion of 519 MBOE from the PUD category to proved developed for the year ended December 31, 2017.

[4] The Partnership acquired 5,430 MBOE and 3,696 MBOE of PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 9,126 MBOE during the year ended December 31, 2017.

[5] The Partnership acquired 11,670 MBOE and 5,823 MBOE of producing developed wells and PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 17,493 MBOE during the year ended December 31, 2017.

[6] Revisions to previous estimates decreased proved reserves by a net amount of 3,391 MBOE. These revisions result from 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule and 1,213 MBOE of downward adjustments related to well performance, which were partially offset by 690 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2017 to December 31, 2016.

[7] Revisions to previous estimates increased proved reserves by a net amount of 112 MBOE. These revisions resulted from 800 MBOE of upward adjustments attributable to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule, 124 MBOE of downward adjustments related to well performance and 217 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2016 to December 31, 2015.Revisions of previous estimates for total proved reserves from December 31, 2015 to December 31, 2016 of 112 MBOE (increase) were less than revisions of previous estimates for proved undeveloped reserves for the same period of 442 MBOE (increase), primarily due to the incremental downward adjustment revisions to the proved developed reserves caused by changes in lower oil, natural gas and NGL prices (206 MBOE) and well performance (124 MBOE).

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 ($)	Dec. 31, 2017	Dec. 31, 2016	Dec. 31, 2015
Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]			
Future cash inflows	$ 860,125,991	$ 320,606,188	
Future production costs	(292,788,015)	(122,527,901)	
Future development costs	(96,111,664)	(43,050,408)	
Future net cash flows	471,226,312	155,027,879	
10% annual discount	(285,321,062)	(94,081,952)	
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927	$ 99,189,842

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, 2017	Dec. 31, 2016
Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]		
Annual discount	10.00%	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 - USD ($)	12 Months Ended	
	Dec. 31, 2017	Dec. 31, 2016
Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows [Abstract]		
Standardized measure at beginning of period	$ 60,945,927	$ 99,189,842
Acquisition of reserves	97,630,985	524,175
Sales of oil, natural gas and NGLs, net of production costs	(25,571,593)	(12,684,015)
Net changes in prices and production costs	85,222,533	(28,508,492)
Development costs incurred during the period	4,279,548	1,652,782
Revisions to previous estimates	(57,488,282)	(3,750,720)
Accretion of discount	6,103,044	9,932,739
Change in estimated future development costs	14,783,088	(5,410,384)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

Quarterly Financial Data (Unaudited) (Details) - Quarterly Financial Information - USD ($)	3 Months Ended								12 Months Ended	
	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2017	Dec. 31, 2016
Quarterly Financial Information [Abstract]										
Total revenue	$ 10,944,738	$ 9,717,996	$ 10,208,740	$ 10,141,266	$ 5,080,081	$ 5,434,047	$ 5,532,113	$ 4,319,097	$ 41,012,740	$ 20,365,338
Net income	$ 2,008,288	$ 1,280,559	$ 1,986,404	$ 2,621,071	$ 732,421	$ (1,511,146)	$ (859,383)	$ (3,592,456)	$ 7,896,322	$ (5,230,564)
Basic and diluted net income per common share (in Dollars per share)	$ 0.11	$ 0.07	$ 0.11	$ 0.17	$ 0.06	$ (0.20)	$ (0.14)	$ (0.73)	$ 0.44	$ (0.69)

Subsequent Events (Details) - USD ($)	1 Months Ended		12 Months Ended	
	Feb. 28, 2018	Jan. 31, 2018	Dec. 31, 2017	Dec. 31, 2016
Subsequent Events (Details) [Line Items]				
Distribution Made to Limited Partner, Cash Distributions Paid			$ 24,578,224	$ 10,448,981
Distribution Made to Limited Partner, Distributions Paid, Per Unit			$ 1.361643	$ 1.400000
Subsequent Event [Member]				
Subsequent Events (Details) [Line Items]				
Distribution Made to Limited Partner, Cash Distributions Paid	$ 1,700,000	$ 1,700,000		
Distribution Made to Limited Partner, Distributions Paid, Per Unit	$ 0.092055	$ 0.092055		

Energy 11, L.P. (Filer) CIK: 0001581552 (see all company filings)

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