Due Diligence Report:

PB Non-op Drilling, LP
December 2023

Offering Sponsor:

Eagle Eye Funds LLC

Prepared by:

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Buttonwood Due Diligence, LLC has been engaged to provide a due diligence review of **PB Non-op Drilling LP.** The purpose of this report is to assist Broker/Dealers, RIAs, and Family Offices in their due diligence responsibilities in determining whether to offer Interests in **PB Non-op Drilling LP** and to help them establish criteria to determine suitability requirements both for their firm and the individual client.

Buttonwood was founded in 2004 to provide due diligence to the Broker/Dealer, RIA, and Family Office communities. Buttonwood has grown to include a staff of professionals with advanced degrees or credentials (including JD, CPA, CFA, MBA and CCIM) comprising extensive combined experience in the financial services industry.

Buttonwood provides concise and prompt program and sponsor reviews that allow for a thorough understanding of a program's merits to Broker/Dealers, RIAs, and Family Offices.

This report is intended to be part of the Broker/Dealer's, RIA's, or Family Office's review. It is not intended to cover all facets of the due diligence that they may require. It should be noted that the NASD (now FINRA) NTM 05-48 addresses the responsibilities of the individual broker/dealer, suggesting they may not rely exclusively on the efforts of a third-party provider. Regarding RIAs, the SEC has advised that when a service provider is utilized, the investment advisor still retains its fiduciary responsibilities for the delegated services. While this report is designed to assist the Broker/Dealer, RIA, and Family Office in their due diligence efforts, it is not designed to replace it.

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PB Non-op Drilling LP

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Introduction

Buttonwood Due Diligence, LLC (Buttonwood) has been engaged by one or more Broker-Dealers/RIAs to provide a due diligence review of **PB Non-op Drilling LP.**

While several points mentioned herein were independently verified, it should be noted that Buttonwood did not engage any independent experts to advise it in its review, except where specifically referenced. Furthermore, Buttonwood has relied upon management for the veracity of the comments made, both verbally and in written form, per the documents reviewed. However, to satisfy the need for independent verification, many documents were cross-referenced to other sources, both internal and external, to test their accuracy.

The purpose of this report is to assist the Broker/Dealer, RIA, or Family Office in their due diligence responsibilities in determining whether to offer LLC Interests in **PB Non-op Drilling LP** and to help them establish criteria to determine suitability requirements both for its firm and for the individual customer. As such, Buttonwood has taken care to provide a "reasonable investigation" as defined in Section 11 and Section 12 of the Securities Act of 1933.

On January 28, 2014, the SEC issued a Risk Alert (Volume IV, Issue 1), in which their Office of Compliance Inspections and Examinations (OCIE) observed the due diligence practices of certain investment advisers that manage and/or recommend alternative investments to their clients. The alert described current industry trends and practices in advisers' due diligence, noting that advisers are:

- Seeking more information and data directly from the managers of alternative investments;
- Using third parties to supplement and validate information provided by managers of alternative investments; and
- Performing additional quantitative analysis and risk assessment of alternative investments and their managers.

Additionally, the SEC staff noted certain deficiencies in several of the advisory firms examined, including:

- Omitting alternative investment due diligence policies and procedures from their annual reviews;
- Providing potential misleading information in marketing materials about the scope and depth of due diligence conducted; and
- Having due diligence practices that differed from those described in the advisers' disclosures to clients.

FINRA NTM 10-22 was released in April 2010 to remind Broker/Dealers of their obligation to conduct a reasonable investigation of the issuer and the securities for each Regulation D offering the Broker/Dealer considers. In order to ensure that it has fulfilled its suitability responsibilities, a Broker/Dealer should, **at a minimum,** conduct a reasonable investigation concerning:

- The issuer and its management;
- The business prospects of the issuer;
- The assets held by or to be acquired by the issuer;
- The claims being made; and

- The intended use of proceeds of the offering.

The scope of the investigation will necessarily depend upon several factors, including the Broker/Dealer's affiliation with the issuer, its role in the transaction and other factors and circumstances of the offering. Each investigation must be tailored to the specific Regulation D offering and cannot rely on a generic "checklist" for review. A Broker/Dealer can engage third party experts to assist in the due diligence process. The Broker/Dealer must note any information that it encounters that could be considered a "red flag" and must follow up on any "red flags" presented in a third-party due diligence report.

This review is intended to be part of the Broker/Dealer's, RIA's, and Family Office's review, and is not intended to cover all facets of that which they may require. While this report is designed to assist the Broker/Dealer, RIA, and Family Office in their due diligence efforts, it is not designed to replace those efforts.

The scope of Buttonwood's analysis inter alia included a review of internal reports, legal documents, and financial information.

While this report is designed to assist the Broker/Dealer, RIA, and Family Office in meeting their due diligence responsibilities, it should be noted that Buttonwood is not involved in any decisions made by the individual Broker/Dealer, RIA and Family Office and makes no recommendations regarding specific programs. Furthermore, this report is solely for use by approved Broker Dealer, RIA and Family Office recipients and cannot be shared with individual investors irrespective of the investor's sophistication, accreditation, or other qualifications.

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Summary and Conclusions

Investment Program Overview	
Issuer	PB Non-op Drilling LP (the "Fund" or "Partnership")
Structure	Limited Partnership
Interest Type	Units of Partnership Interest – See Offering Overview below
Maximum Equity Raise	$5,000,000 – expandable to $10,000,000
Minimum Equity Raise	No minimum
Minimum Purchase	1 Unit for $100,000 – minimum can be waived by Managing GP
Current Program Raise	N/A-New Offering
Distribution Rate	Allocations and Distributions totaling 15% per annum. See Distributions below
Liquidity	Illiquid. No redemption program is in place
Projected Hold Period	Up to 10 years Per management, a sale will be targeted for 12-36 months after the wells come online

Investment Overview	
Investment Focus	Acquisition of non-operated working interests in wells that are in current drilling programs of established operators.
Types of Property	Producing mineral properties
Locations	Permian Basin – Delaware and Midland basins
Business Plan	The Partnership was formed to acquire non-operating Working Interest in prospective oil and gas wells to be drilled and related leaseholds in the Permian Basin located in West Texas and Eastern New Mexico. The Partnership plans to bid on non-operating Working Interests in oil and gas wells that currently scheduled to be drilled in the Permian Basin.
Investment Objectives	The primary investment objective of the Partnership is to drill or rework oil and gas prospects and produce oil and gas in commercial quantities.

Registration and Offering Documents	
Investor Suitability	Accredited Investors[1]
Registration Exemption	This is a Rule **506(c)** of Regulation D offering.
Form D Filing Date	October 30, 2023
Original PPM Date	October 05, 2023
Restated PPM Date	N/A
PPM Supplement Dates	N/A
Offering Termination Date	March 31, 2024[2] – extendable for 30 days

[1] As defined by Regulation D under the Securities Act of 1933. Net worth of $1 million exclusive of a person's primary residence (a person need not deduct from his or her net worth the amount of the mortgage debt secured by his or her primary residence, except to the extent that the amount of mortgage liability exceeds the fair market value of the residence) or gross annual income of $200,000 ($300,000 jointly with spouse) for current and previous 2 years. Certain institutions and trusts with total assets over $5 million also qualify.
[2] The PPM currently lists the offering close date as December 31, 2023. Management has expressed that they will be updating the PPM to reflect an updated close date of March 31, 2024.

Parties to the Transaction	
Sponsor	Eagle Eye Funds LLC
Issuer	PB Non-op Drilling LP (the "Fund" or "Company")
Issuer Contact	Richard Loomis
Issuer Contact Information	richard@epusenergy.com
Managing General Partner	PB Non-op Drilling GP, LLC
Managing Broker Dealer	None
Escrow Agent/Bank	None – no minimum
Operator	Acquiring non-operated interest. Operator will be determined based on working interest acquired.
Transfer Agent	N/A
Accounting Services	SkyGroup LLC[3]
Valuation Services	No third-party process for ongoing unit valuation. Units will be valued at market value and sold at a PV-12 valuation. BW How market value will be determined was not specified.
Legal	N/A

Summary Data Points	
Offering Load	12.00% (Assuming $5,000,000 raise)
Cost Plus Fee	10.00% of well and/or leasehold costs
Finder's Fee	3.00% of acquisition price
Well Fee	Not specified. Likely part of the operating agreement – to be determined once an asset has been acquired
Sponsor Ownership	The owners of the Managing Partner will own Limited Partner units

Conclusions

Investment Methodology

- The Fund will be acquiring non-operated working interest in the drilling programs of highly experienced operators. Given the resources and experience that these operators possess, there is an increased likelihood that targeted wells will be completed in a professional manner and as advertised.
  - One downside to buying into the drilling programs of larger operators is that even with a $5mm - $10mm capital raise, the working interest acquired in the drilling program will potentially be a significantly minority position such as 0.2%-0.3% of the working interest. As such, the Fund will have little to no say regarding drilling, completion, operations, sale of product, etc.

[3] Located in Elk City, Oklahoma, SkyGroup is a small provider of HR and DOT compliance services for the trucking and saltwater disposal industries. Buttonwood was able to locate an older Facebook page for SkyGroup but no website appeared to be active.

- The Fund will invest in projects in the Midland and Delaware Basins of the Permian Basin.
    - Measuring in at more than 75,000 square miles, the Permian Basin is by far the most productive oil region in the U.S., with more than 30 billion barrels extracted over the last 100 years and estimates of an additional 20 billion extractable barrels.
    - The targeted Delaware and Midland Basins have experienced explosive production growth over the last 10+ years as a result of the use of more sophisticated horizontal drilling techniques.
        - Since 2010, Delaware Basin production has increased from 80,000 barrels per day to 2,100,000 barrels per day. Midland Basin production has experienced a similar jump, growing from 350,000 barrels per day to 1,900,000 barrels per day.
    - An additional benefit to Permian Basin production is the extraction cost per barrel. The Delaware and Midland Basins offer the lowest per barrel extraction costs of all major U.S. production regions, at $46 and $52 per barrel, respectively.

Fees and Expenses

- The Fund will be subject to a cost-plus 10% fee arrangement on the working interest obligations of the Fund.
    - This type of fee is common in the industry and is typically assessed to compensate the Operator for drilling or overseeing the drilling of the program's wells. However, the Fund will be an entirely passive working interest owner with no control or influence over the drilling of the Fund's wells, making this fee somewhat atypical.
    - This fee is estimated at $426,800 for a $5mm raise and $858,450 for a $10mm raise.

- The offering related fees and expenses are considered average at 11.50%-12.00% of capital raised (varies based on amount raised) when compared with similarly structured programs. However, the Fund will also be assessed a finder's fee of 3.0% on net invested capital which takes the front-end load up to 14.16%-14.64%.

Distributions and Capital Calls

- Investors are targeted to receive an annual Preferred Return of 15.0% payable potentially monthly, but not less frequently than quarterly.
    - Distributions beyond 15.0% will be split 50/50 between the Investors and the Managing GP.
    - Upon winding up or sale of the Partnership assets, Investor Partners receive a return of invested capital plus the amount necessary to provide a 15.0% return per annum. To clarify, if any accruals are outstanding and payable to the Investors, these accruals, and a return of invested capital, will be paid prior to the Managing GP participating in exit distributions.
    - Distributions are limited to cash flows derived from oil and gas production, which eliminates the potential for capital raise proceeds or debt to be utilized to pay distributions.

- Investor Partners may be required to make additional capital contributions beyond their initial investment. These contributions may be requested to fund Operating Deficits or to conduct Subsequent Operations. Follow the preceding links for more detail.
    - To the extent possible, each Partner's share of an Operating Deficit will be paid out of cash available for Distributions. However, The Managing GP may, at its election, request that each Investor Partner pay their share of the Operating Deficit as the deficits occur.
    - In the event a capital call is issued to fund subsequent operations, the financial penalty for non-compliance has the potential to be significant. To elaborate, investors electing to not participate in the capital call (defaulting partner) will have Distributions withheld until such time as the person or entity which pays the defaulting Partner's assessed share of Subsequent Operations shall have received

additional Distributions in an amount equal to five hundred percent (500%) of the amount he paid on behalf of the defaulting Partner.
    - This type of penalty for non-participation in capital calls is common; however, Buttonwood typically sees a penalty of 300% of the amount vs. the 500% noted for this program.
  - Management has expressed that they have no intention of issuing capital calls. If additional capital is required, they will look to raise the capital from additional investors as opposed to going back to existing investors for more capital.

- In the event the Partnership terminates, and the assets are unable to be sold, the Partners **may receive individual Working Interests in the Partnership Wells**. At that time, the Partners may find it advisable to obtain additional (and possibly quite expensive) personal liability insurance to provide them with coverage commensurate with this new form of ownership.

Financial Projections

- Projected investor returns as calculated by Buttonwood are strong in the base case (Manager's basic assumptions - i.e., $80/bbl oil, $3/mcf gas) with a PV-12 calculation at exit, ranging from an IRR of 15.71% up to 18.11% depending on year of exit. As would be expected, returns taper off when utilizing a PV-20 exit valuation as the higher discount rate devalues future cash flows more, although base case returns are still solidly in the mid-teens for IRR.
  - When testing down case scenarios of $60 oil and $2.50 gas, projected returns fall into the low teens, high single digits, but are still reasonable across the PV-12 and PV-20 scenarios. Breakeven pricing knocks returns down, even dropping into negative territory for a long-term hold in the PV-20 scenario.
  - The projected returns described above do not include any potential tax benefits to investors.
  - See the Financial Projections section for more detail.

- Mirroring the trends noted in the IRR analysis above, MOIC is respectable across the base case and initial down scenarios, with some scenarios exceeding 2.0x (not including the $100 oil up case). In the breakeven scenario with a longer-term hold, returns potentially drop to a level just sufficient to return capital, although as previously noted, these projected returns do not factor in the potentially significant tax benefits potentially recognized by some investors.
  - See the Financial Projections section for more detail.

Tax Considerations

- As with most drilling programs, Fund investors will be allocated certain tax benefits such as Intangible Drilling Costs (IDCs), depreciation and depletion which may provide a notable financial benefit to those investors capable of utilizing the benefits.
  - The IDC allocation available to investors may represent an amount as high as 80%-88% of the invested amount if the Managing GP is able to allocate 100% of the IDC costs to the Investor General Partners.
  - However, investors need to be aware that if the assets are sold as planned within two to four years, there will likely be an IDC recapture event. If an investor becomes subject to IDC recapture at ordinary income tax rates, the initial IDC benefit will in effect become a simple deferral of the original tax liability. However, it should be noted that by deferring the tax liability through the IDC benefit, investors theoretically could put more capital to work in the short term while deferring the tax liability initially offset by the IDC benefit.
  - An investor can potentially avoid tax on IDC recapture if the proceeds from sale are reinvested in a similar program with IDC benefit.
  - For more information, see the Tax Impact section of the report.

Investor Liability and Influence

- Investor GPs will have unlimited liability for the Fund's activities until they are converted to limited partner status, which is expected to occur January 1, 2025. This liability could result in an investor being required to make payments, in addition to their original investment, in amounts that are impossible to predict because of their uncertain nature.
  - Note that liability does not end with conversion to LP status. An investor remains exposed to liability for all activities that transpired during their time as a GP. For example, if an environmental issue arises years after conversion to LP status, from activities that occurred during the period when an investor was classified as a GP, the investor retains liability for any such issues. However, it should be noted that Fund assets as well as notable liability insurance will be in place to help absorb any such liability.
  - Buttonwood recommends continued confirmation (through individual effort or Buttonwood AIM reporting) that Fund insurance remains in place and effective.

- The Managing GP will have seventy-five (75%) of the Partnership's voting interest. As such, the Investor Partners will not have a vote that could affect the Partnership's decisions unless the Managing GP chooses to abstain from voting.
  - Removal of the Managing GP is based on a vote of those partners holding rights to distributions, which creates the opportunity for investors to vote on the matter of removal; however, any removal of the Managing GP requires a 75% threshold to remove. Buttonwood prefers to see a threshold closer to simple majority.

- There are other risk factors noted in the PPM, which should be reviewed.

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Overview

Offering Overview	
Suitability	Accredited and Sophisticated Investors only.
Type of Interests	**Units of Limited Partner and Additional General Partnership Interest** • 50 Units, expandable to 100 Units • To be acquired by investors in the offering
Offering Details	(see table below)
Offering Termination Date	March 31, 2024[4] • Extendable for 30 days
Business Plan	The Partnership plans to participate in oil and gas well prospects in the Permian Basin, all subject to the Managing General Partner's discretion as to operations to undertake. The oil and gas production wells will primarily target the Permian Basin's Delaware Basin and the Midland Basin, though other areas may be targeted. The targeted formations include, but are not limited to, the Wolfcamp, Bone Spring and Spraberry Formations.
Investment Objectives	The primary investment objective of the Partnership is to participate in the drilling of oil and gas prospects in the Permian Basin alongside qualified operators who would operate the oil and gas wells.
Participation Rights	**Separate Offerings** Rights to participate in additional related offerings were not specified in the PPM.

Offering Details:

	Amount	# Units	Price/Unit
GP/LP Units			
Maximum Offering (1)	$5,000,000	50	$100,000
Minimum Offering (2)	N/A	-	
Minimum Investment (3)	$100,000	1	

Note 1: Expandable to $10,000,000
Note 2: The Offering is not contingent on any minimums.
Note 3: Minimum investment amount can be waived by the Managing GP.

Investment Considerations	
Investor GP Considerations	**GP Tax Benefits** Investors are expected to have the opportunity to receive a tax deduction against their taxable income for their pro rata portion of 100% of the intangible drilling costs (IDC) incurred or prepaid towards

[4] The PPM currently lists the offering close date as December 31, 2023. Management has expressed that they will be updating the PPM to reflect an updated close date of March 31, 2024.

	drilling projects that the Fund participates in during each tax year during the Fund's term. The total IDC deductions available to the Fund will be proportional to the percentage of working interest purchased, which will likely represent a value less than the total capital contributions of the Fund.
	BW Investors may recognize additional tax benefits from depreciation and depletion deductions that will occur over time as oil and gas resources are depleted.
	
	GP Unlimited Liability
	Investor GPs will technically have unlimited liability for the Fund's activities until they are converted to limited partner status, subject to certain exceptions. This liability could result in an investor being required to make payments, in addition to their original investment, in amounts that are impossible to predict because of the undefined nature of any potential issue that may arise.
	
	A GP investor may become subject to certain liabilities and obligations, including but not limited to:
	• Contract liability, which is not covered by insurance;
	• Liability for pollution, abuses of the environment, and other environmental damages, including but not limited to, the release of toxic gas, spills or uncontrollable flows of natural gas, oil or well fluids, including underground or surface contamination against which the Managing GP cannot insure because coverage is not available or against which it may elect not to insure because of high premium costs or other reasons; and
	• Liability for drilling hazards that result in property damage, personal injury, or death to third parties in amounts greater than applicable insurance limits. Drilling hazards include but are not limited to:
	  o Well blowouts, fires, and explosions.
	  o If the liability coverage provided by the operator and major subcontractors and the assets of the Fund are not sufficient to satisfy any liability, then the Managing GP may call for additional funds from investors and the other GPs to satisfy the liability. Additionally, any of the drilling hazards may result in the loss of the well and the associated revenues.
	• Finally, a GP may have liability if the Fund does not properly plug and abandon a well.
	
	BW Note that liability does not end with conversion to LP status. An investor remains exposed to liability for all activities that transpired during their time as a GP. For example, if an environmental issue arises several years after a GP's conversion to LP status, from activities that occurred during the period when the investor was classified as a GP, the investor retains liability for any such issues. While Fund assets and insurance coverage may provide an initial line of defense against any such liability, it is impossible to protect and insure against all potential liabilities.

GP Conversion	On January 1st of the year immediately following the year in which the Fund has deployed 90% of the capital contributed by Investor Partners, the Managing GP may convert the GP Units to LP Units. BW This is **not an automatic conversion** which is somewhat atypical. The Managing GP retains the ability to determine if conversion to LP units would not be in the best interests of the General Partners or of the Partnership. If conversion is delayed, the Managing GP will continue to have the power to determine if conversion to LP units is in the best interest of the General Partners or of the Partnership.

	This possibility that conversion may be delayed may expose investor GPs to additional liability. As noted in the Investor GP Considerations section above, GPs are liable for the activities of the Partnership that occur during their time as General Partners. A delay in conversion extends the potential period of time for which the GPs are liable for Partnership actions.
Liquidity	• This is an illiquid investment. • There is no market for the sale of such units, nor is one likely to develop.
Redemption Feature	The Managing General Partner has no obligations to repurchase any Partnership Units.
Leverage	Per the Partnership Agreement, the Partnership does not have the authority to borrow money, enter loan agreements, or otherwise place debt on its balance sheet (other than trade creditor debt). As such, debt service should not be a notable consideration for the Partnership. However, the Partnership Agreement is somewhat ambiguous as to the ability of the Investor Partners to approve the use of debt. Section 3.3 of the Partnership Agreement states; “The Partnership shall not be permitted to borrow money to fund its operations without the consent of the Majority-In-Interest of the Investor Partners.” This provision appears to grant the Partnership the ability to borrow to fund operations provided the Investor Partners approve with a majority in interest.
Exit Strategy	**Exit Strategy** The PPM and related documents do not specify a defined exit plan. Management has expressed that the Fund will seek to sell its assets 12-36 months after the wells have been drilled. **Winding Up of the Partnership** The Partnership may be terminated upon the occurrence of certain events including the sale of Partnership assets. There is no assurance that such assets will be marketable or that competitive prices can be obtained for these assets. In the event the Partnership terminates, and the assets are unable to be sold, the Partners **may receive individual Working Interests in the Partnership Wells**. At that time, the Partners may find it advisable to obtain additional (and possibly quite expensive) personal liability insurance to provide them with coverage commensurate with this new form of ownership. Partners may concurrently find it more difficult to dispose of such interests because of the diversity of owners and interests involved. Investors need to be aware that the potential exists for working interest to transfer to the investor partners which would create liability for the partners that would need to be insured against. As noted in the statement above, this insurance coverage may be notably expensive for the investor to put in place.

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Distributions and Allocations

<table>
<tr><th colspan="2">Distributions, Profit and Loss Allocation</th></tr>
<tr><td>Distributions</td><td>Distributions will be targeted to be paid monthly, but if monthly is not possible, no less frequently than quarterly.
The Managing GP will determine the amount available to distribute to the Partners after factoring in amounts necessary to pay current debts and obligations and after accounting for any potential reserves.</td></tr>
<tr><td>Preferred Return</td><td>Each Investor Partner will receive an annual preferred return of 15.0% of contributed capital.
This 15.0% will accrue at a rate of 1.25% monthly.</td></tr>
<tr><td>Investor Partners Distributions</td><td>
<table>
<tr><th></th><th>Investor Partners Receive</th></tr>
<tr><td>Preferred Return</td><td>15.0%: accruing at a rate of 1.25% per month.
Amounts not paid in the current period will be paid upon winding up or sale of the assets (see below)</td></tr>
<tr><td>Return of Capital and Preferred Return Catch Up</td><td>Upon winding up or sale of the Partnership assets, Investor Partners receive a return of invested capital plus the amount necessary to provide a 15.0% return per annum. To elaborate, if any accruals are outstanding and payable to the Investors, these accruals, and a return of invested capital, will be paid prior to the Managing GP participating in exit distributions.</td></tr>
<tr><td>Thereafter</td><td>Any additional allocations or distributions will be shared 50/50 by the Managing GP and Investor Partners.</td></tr>
</table>
The Partnership Agreement refers to distributions as “allocations and distributions” when referring to the payment of the Preferred Return and of a return of capital. As such, the potential exists that Investor Partners may receive allocations of Partnership assets (such as working interest) instead of cash when distributions are made. If working interest was allocated in lieu of cash, this would likely only occur upon winding up of the Partnership.</td></tr>
<tr><td>Distribution Sources</td><td>Limited to cash flows derived from oil and gas production.</td></tr>
<tr><td>Projected Distributions</td><td>See Financial Projections for potential investor return estimates.</td></tr>
<tr><td>Additional Capital Contributions</td><td>Investor Partners may be required to make additional capital contributions beyond their initial investment. These contributions may be requested to fund Operating Deficits or to conduct Subsequent Operations. See below or follow the preceding links for more detail.
Per discussions with Management, there are no plans to utilize capital calls.</td></tr>
<tr><td>Operating Deficits</td><td>If the Partnership’s share of Lease Operating Costs, the Management Fee and its General and Administrative Expenses for any calendar month exceed the sum of the Partnership’s revenues from</td></tr>
</table>

	the Prospects, the Managing GP will debit each Partner's Capital Account with the amount of his share of the Operating Deficit. • To the extent possible, each Partner's share of an Operating Deficit will be paid out of cash available for Distributions. However, The Managing GP may, at its election, request that each Investor Partner pay their share of the Operating Deficit as the deficits occur. BW Per discussions with management, an attempt will be made to bring in additional investors to fund any capital needs prior to issuing capital calls to the existing investors.
Cost Allocations	The following table provides the percentage allocation of costs within the Partnership between the Partners and the Managing General Partner.

	Investors	Managing GP
Organizational Fees	100.0%	0.0%
AFE Costs	100.0%	0.0%

Investment and Activities Overview

Investment Overview	
General Overview	The Partnership plans to participate in oil and gas wells in the Permian Basin (the "Partnership Wells"). The oil and gas production wells will primarily target the Permian Basin's **Delaware Basin** and the **Midland Basin**, though other areas may be targeted. • The targeted formations include, but are not limited to the Wolfcamp, Bone Spring, and Spraberry Formations. BW Note that the targeted areas of the Midland and Delaware Basins, combined further with plans to target the Wolfcamp, Bone Spring and Sprayberry formations casts a very broad net as these areas comprise the bulk of the Permian Basin's productive areas. As such, the Partnership may acquire non-operated working interest in just about any part of the greater Permian Basin area. BW For more information on the Permian Basin as well as the targeted Delaware and Midland Basins, see below.
Well Locations	The Managing GP or Operator may determine the location of wells to be drilled and it is possible that such locations may change prior to drilling. The Managing GP will, on behalf of the Partnership, participate in such decisions to the extent of the Partnership's rights. It is possible that the Operator could decide not to drill Partnership Wells in the locations and according to the plan described in this report and in the PPM. BW The Partnership will acquire non-operated working interest based on the available opportunities once capital has been raised. As such, investors may not have the opportunity to evaluate the specific opportunity or location to be drilled/developed.

	BW Management clarified to Buttonwood that the Managing GP will decide which wells to participate in after the decision to drill the well has been made by the Operator.
Operator	The Managing GP will not operate the wells. The Operator designation will depend on the Partnership winning the bid for the nonoperating Working Interest. BW As such, investors will potentially not have the opportunity to evaluate the quality of the Operator prior to investing. However, per materials reviewed by Buttonwood, the Managing GP intends for the Partnership to invest alongside high quality, tenured operators.
Subsequent Operations	Subsequent Operations are those operations determined to be required after the drilling and completion of the Prospect Wells by the Operator pursuant to the terms of the AFE. If Subsequent Operations are proposed by the Operator or another Working Interest owner, and the Partnership consents to such operations, the Managing GP may, at its election, pay for the Partnership's share of such Subsequent Operations **from cash available for Distributions** generated by revenues from the Prospects. Alternatively, the Managing GP **may request that each Partner make** a Subsequent Operations Contribution to the Partnership in cash. Partner's may elect to "nonconsent" to the proposed Subsequent Operations, whereby the Partner becomes a "defaulting Partner." In the case of a defaulting Partner, the Managing GP shall have the option of either: • Paying the amount of the defaulting Partner's Subsequent Operations Contribution or, • Allowing another Partner to do so or, • Allowing a third party to be admitted to the Partnership as a Substitute Limited Partner for the purpose of paying the defaulting Partner's Subsequent Operations Contribution. In such event, Distributions shall be withheld from the defaulting Partner until such time as the person or entity which pays the defaulting Partner's assessed share of Subsequent Operations shall have received additional Distributions in an amount equal to five hundred percent **(500%)** of the amount he paid on behalf of the defaulting Partner. Once the paying Partner has received this sum, the payment of Distributions to the defaulting Partner shall be resumed. BW Given the language noted above, investor Partners should be prepared for the possibility of requested additional capital contributions. Non-participation in Subsequent Operations that require additional capital contributions may carry a substantial financial penalty. BW As a hypothetical numeric example of the penalty for non-participation, assume the following: an Investor Partner "A" makes an original investment of $500,000 in the Partnership. Following deployment of the Partnership's capital raised, the Operator and/or Managing GP determines that additional work is required to improve the Partnership's wells. To accomplish this, the Managing GP votes to conduct Subsequent Operations funded by additional capital contributions. Investor Partner "A" is required to contribute an additional $100,000 based on his percentage ownership in the Partnership. Investor Partner "A" elects to "non-consent" in the Subsequent Operations, prompting Investor Partner "B" to fund "A's" share of the capital call. At this time, distributions to Investor Partner "A" are halted until Investor Partner "B" has received additional distributions totaling $500,000 – which is 500% of the amount funded by "B" when "A" elected to non-consent. Prior to "A" electing to non-consent, "A" was receiving

	15% distributions annually, equivalent to $75,000 per year based on an original $500,000 investment. Given that rate of distribution, Investor Partner "A" may wait 7 years for his $75,000 per year distribution to repay the 500% penalty payable to Investor Partner "B" when "A" non-consented. To be fair, the Subsequent Operations conducted may increase production, thereby increasing distribution rates, which may shorten the repayment period to "B." The point of the scenario above is to illustrate that an Investor Partner who elects to no-consent to subsequent operations may see their distributions halted until several years later. • Buttonwood notes that the average penalty assessed for non-compliance with additional capital calls is 300% for many programs viewed by Buttonwood vs. the 500% noted above. • It should be further noted that while the above potential penalties are important to note and understand, management does not intend to issue capital calls.
Investment Sourcing	The Partnership Wells will be sourced from Whitefish Management, LLC. Jake Johnson, (see Management section) is a member of Whitefish Management, LLC.
Leases	In the event that the Partnership acquires leased acreage: **Ownership** Record title to each Lease or each interest in a Lease acquired by the Partnership may be temporarily held in the name of the Operator, an affiliate of the Operator, the Managing General Partner, or in the name of any nominee designated by the Managing General Partner, as agent for the Partnership until a productive well is completed on a Lease. Thereafter, record title to Leases shall be assigned to and placed in the name of the Partnership. The Managing GP shall take the necessary steps in its best judgment to render title to the Leases to be assigned to the Partnership acceptable for the purposes of the Partnership. The Managing GP shall be free to use its own best judgment in waiving title requirements and shall not be liable to the Partnership or Partners for any mistakes of judgment unless such mistakes were made in a manner not in accordance with general industry standards in the geographic area. Neither the Managing GP nor its Affiliates shall be deemed to be making any warranties or representations, express or implied, as to the validity or merchantability of the title to any Lease assigned to the Partnership or the extent of the interest covered thereby. • The potential chain of ownership described above (temporarily held in name of Operator or Managing GP) is standard for oil and gas programs such as this one. Furthermore, as noted in the second paragraph, the Managing GP is often self-absolved of responsibility relating to mistakes of judgement regarding title requirements or the overall validity of title. While this release of liability is common within the industry, it is notable for investors to be aware of the lack of recourse should potential issues with title arise.
Identified Properties	The Partnership will invest in working interest in a project operated by an established and well-known producer (i.e., Occidental Petroleum "Oxy", Mewbourne, etc.). **<u>This investment opportunity will not be fully identified and selected until the Partnership has raised capital.</u>**

Affiliated Transactions	The PPM states that Whitefish Management (the entity responsible for sourcing investment opportunities) is not affiliated with the Managing GP or Partnership. However, the following affiliations are present: • Jake Johnson is a beneficial owner of Crimson Creek Holdings, which partially owns the Managing GP. Jake Johnson is also a Member of Whitefish Holdings. • Jake Johnson is related to Jeff Johnson who owns High Plains Oil. High Plains Oil is an owner of the Managing GP. BW Whitefish Management is not a direct subsidiary or affiliate of the Managing Partner; however, affiliation is present through individual entity ownership and interpersonal relationships. BW Buttonwood does not view the planned transactions with affiliates as atypical or specifically negative. BW See the Conflicts of Interest section for additional detail.
Partnership Termination	The Partnership may be terminated upon the occurrence of certain events, including the sale of Partnership assets. The possibility exists that such assets will not be marketable or that competitive prices cannot be obtained for these assets. In the event the Partnership terminates, and the assets are unable to be sold, the **Partners may receive individual Working Interests** in the Partnership Wells. • If Partners receive working interest in lieu of cash, the Partners will likely need to obtain potentially expensive personal liability insurance to cover the various liabilities associated with ownership of working interest. • Furthermore, if the Managing GP decides to distribute working interest to the partners in lieu of cash, this allocated working interest will be spread across numerous partners, making any potential future sale of the interests much more difficult. BW If the Managing GP decides to distribute working interest in lieu of cash, that is a potential sign that the capital required to operate or rework the wells, or the liabilities associated with the wells represented by the working interest outweigh the benefits, rendering a sale difficult. In such a case, transfer of the working interests to the Investor Partners may result in notable expense and potential liability for the Investor Partners.

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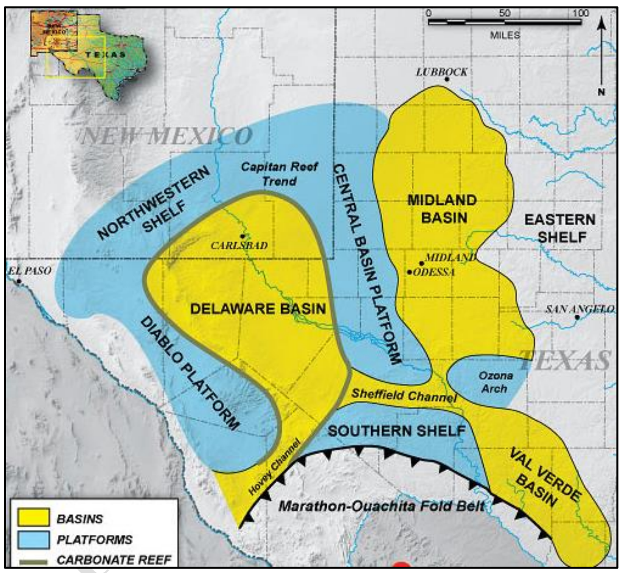
Targeted Areas of Operation

Permian Basin Overview

Permian Basin History and Overview

The Permian Basin takes its name from the Permian geologic timeframe approximately 251 to 291 million years ago. The recent shale revolution that has occurred in the U.S. has largely been possible because of the vast prehistoric sea that dominated the region during the Permian period, which deposited rich organic material over millions of years to form one of the thickest hydrocarbon structures in the world. However, the Permian Basin is not uniform, with deeper zones of sedimentary rock forming the Midland and Delaware Basins and the shallower Central Basin Platform forming a bridge between whose prehistoric reefs were ideal for trapping large oil deposits. At more than 75,000 square miles, the Permian covers an area of about 250 miles wide and 300 miles long in 52 counties in west Texas and southeast New Mexico.

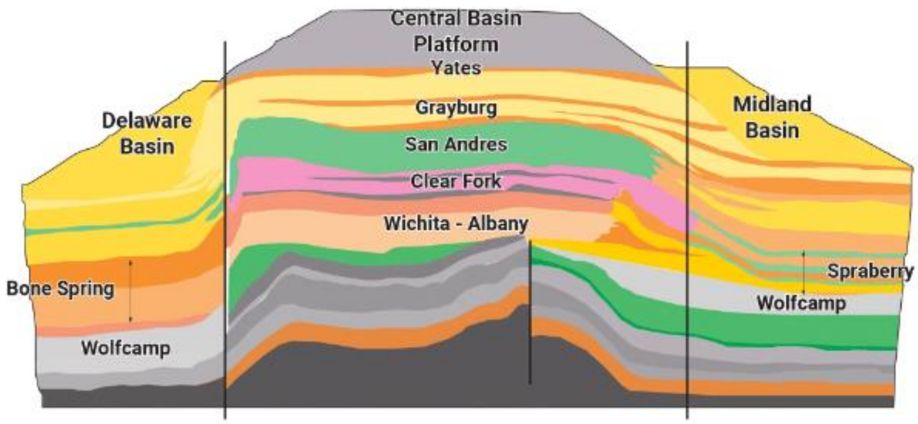


Since the first well drilled in the basin in July of 1920, over **30 billion barrels** of crude have been recovered, with experts predicting there are at least **20 billion barrels** remaining.

Permian Basin Composition

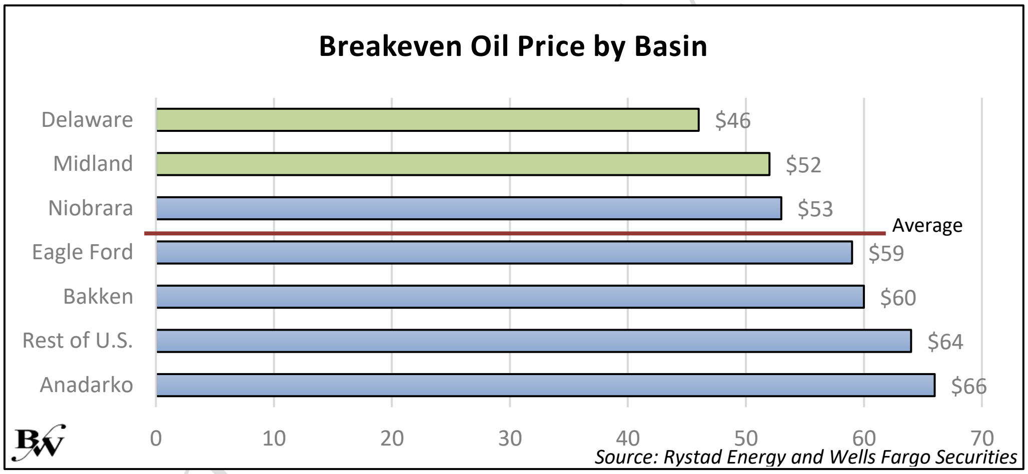
One of the Permian Basin's defining characteristics is its stacked pay. While this feature is not exclusive to the Permian, its magnitude of stacked pay is considerably greater than what is seen in most other unconventional plays in North American. For example, the thickness of the hydrocarbon column being currently developed is over 2,000 feet in the Midland and Delaware basins, compared to 300 feet and 500 feet in the Williston Basin in North Dakota and Eagle Ford trend in South Texas.

- Pay zones can be thought of as commercially viable areas for landing a well that are available from a single surface location. To elaborate, from a surface location, multiple wells can be drilled targeting the various pay zones utilizing vertical and/or horizontal wells across a wide range of stacked zones as shown in the graphic below.



Breakeven Oil Price

Oil production in the Permian Basin is highly cost competitive on a per-barrel basis. As noted in the chart below, when considering the major production basins in the U.S., the Delaware and Midland basins rank as some of the most competitively priced areas to extract oil.



Source: Rystad Energy and Wells Fargo Securities

As noted in the [Market Outlook](#) section below, oil prices have been, and will continue to be volatile. As such, a low price per barrel will be a vital consideration for any drilling program going forward. The projected breakeven price of \$46/bbl and \$52/bbl for Delaware and Midland wells, respectively, positions Partnership production favorably relative to pricing in other notable U.S. basins. However, the Partnership may need to recognize even lower breakeven pricing on an ongoing basis to keep pace with potential future declines in oil pricing.

Delaware Basin Overview

Overview

Located on the western section of the Permian Basin, the Delaware Basin covers a 6.4M acre area. It is the deepest of the Permian subbasins with the thickest deposits of rock. It is heavily faulted compared to the Central Basin Platform and Midland Basin with overpressured reservoirs on the eastern side. Primary targets in the basin are the organic-rich units within the Wolfcamp and Bone Spring groups.

In addition to its vast oil and gas reservoirs, there are a wide variety of subsurface natural resources in the region, including major sylvite formations that yield a steady supply of potassium salts (potash), a byproduct of which is rock salt. The arid conditions of the New Mexico and Texas state line provide a source of sand, which operators use as proppant for hydraulic fracturing. As much as **10 barrels of water** are produced for every barrel of oil in the Delaware Basin, however, the high salt content makes produced water unsuitable for fracturing, requiring operators to dispose of saltwater through injection wells.

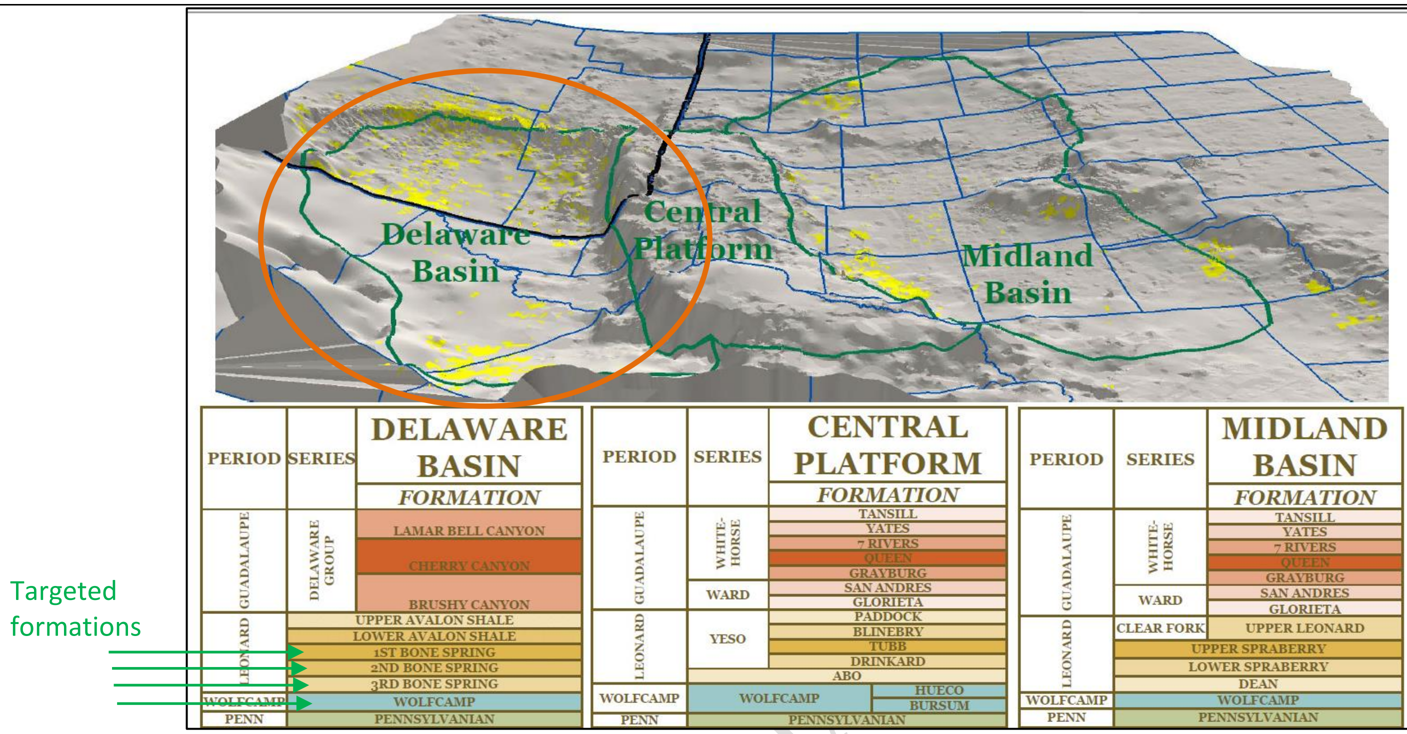
- This water production is notable as water disposal in these volumes can add as much as $5/bbl - $10/bbl for each barrel of oil produced.

In 2010, the introduction of horizontal drilling dramatically increased Delaware Basin oil output from approximately 80 Mbbl/d to 2.1 MMbbl/d at the beginning of 2020. While the basin has shown great potential in terms of resource and economics, the basin's structural varied lithological complexities have led to a wide disparity in results across the play, much of which is driven by parent-child well interactions both within and across landing zones.

- To clarify, some "child" wells often have the undesirable effect of tapping into or communicating across formation pressures, resulting in lackluster performance for the well and sometimes even a production decline for the parent well.
- Parent wells are the initial wells drilled on acreage, often drilled to satisfy requirements to hold the acreage. "Child" wells are the infill wells drilled to further develop the acreage.

Partnership Targets

The Partnerships wells will target the Bone Spring and Wolfcamp formations of the Delaware Basin.



Midland Basin Overview

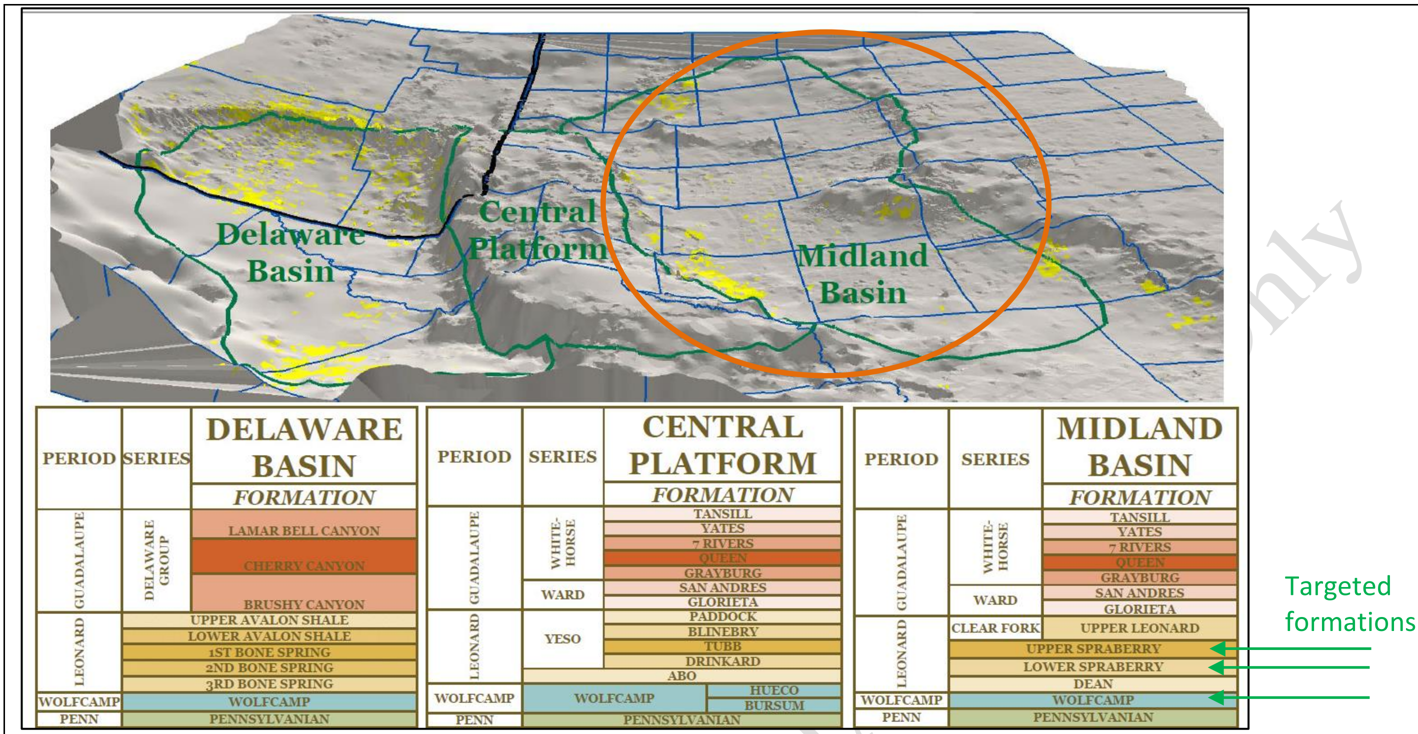
Overview

The Midland Basin boasts the first discovery well and first commercial well of the Permian Basin. Its geology can be thought of as a mirror image of the Delaware, dipping towards the west where it is bounded by the Central Basin Platform. Similar to the Delaware, historical development focused on shallower sandstone and carbonate targets sourced from the basin's peripheral features and deposited during Early Permian Epoch, referred to as the **Spraberry** group in the Midland. Modern development in the basin is focused on the organic-rich units within the **Wolfcamp** and **Spraberry** groups. Horizontal drilling and hydraulic fracturing technologies effectively quadrupled the Midland Basin's production in 2012.

In 2012, the introduction of horizontal drilling dramatically increased Midland Basin oil output from approximately 350 Mbbl/d to 1.9 MMbbl/d at the beginning of 2020. While the basin's path to modern unconventional development was paved by operators in the shallower southern end of the basin, rapidly increasing gas-oil-ratios characteristic of the basin have made the area unfavorable economically compared to the deeper, oilier northern end of the basin where most current activity is located.

Partnership Targets

The Partnerships wells will target the Spraberry and Wolfcamp formations of the Midland basin.



Market Outlook

Short Term Oil Outlook and Pricing

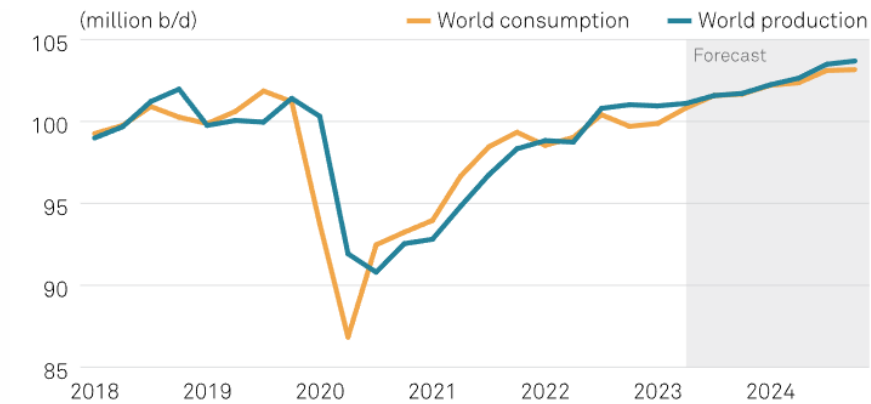
Global Oil Markets

Per the US Energy Information Agency (EIA), following the OPEC+ announcement on June 4, 2023 to extend crude oil production cuts through 2024, the EIA forecast global oil inventories to fall slightly over the next year. EIA expects these draws will put some upward pressure on crude oil prices, notably in late-2023 and early-2024. However, while oil output from the OPEC+ is expected to fall by 300,000 b/d in 2023 largely due to the voluntary cuts, output from non-OPEC producers is seen driving growth of 1.5 million b/d in global liquid fuels production this year.

At the same time, global liquid fuels demand led by China and India is seen rising by 1.6 million b/d in 2023. The EIA raised its global oil demand outlook by 120,000 b/d for 2023 to 100.99 million b/d.

The EIA has also opined that this demand growth would bring the global oil market into balance between the third quarter of 2023 and first quarter of 2024, pushing the Brent price from current levels back to $75-$80/b.

However, the EIA expects consistent global oil inventory builds beginning in Q2 2024 **as global production outpaces global demand to pressure on crude oil prices**. As noted in the chart below, world oil production is expected to equal supply for the first half of 2024 before supply starts to outpace consumption later in 2024.



Source: US Energy Information Administration

Based on the above noted divergence in supply/consumption, as well as additional research conducted by Buttonwood through other sources, Buttonwood's expectation is that oil prices will trend down mildly from 2024 through 2025 and 2026. See Oil Price Projections below for more detail.

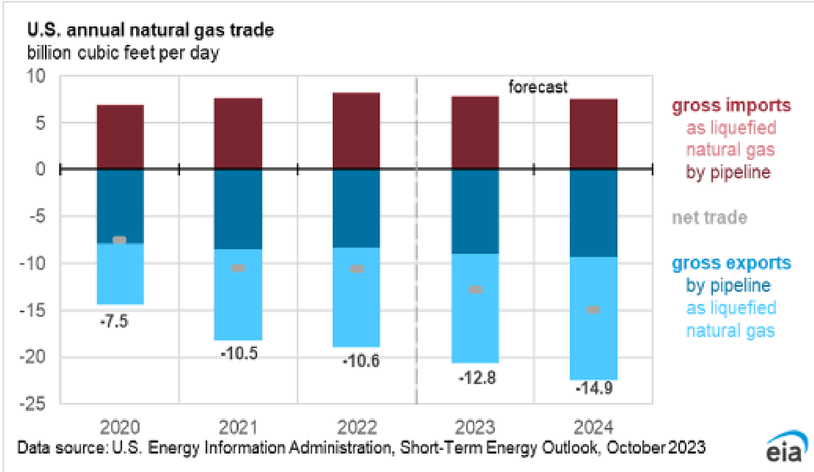
Global Natural Gas Markets

Per the US Energy Information Agency (EIA), U.S. natural gas exports will reach an annual record in 2023 and will continue to grow in 2024. U.S. net exports of natural gas in the EIA projections indicate 20% year-over-year increase, averaging 12.8 billion cubic feet per day (Bcf/d). Increases in liquefied natural gas (LNG) exports and pipeline exports to Mexico drive the overall increase, while natural gas imports are expected to decline from 2022 levels.

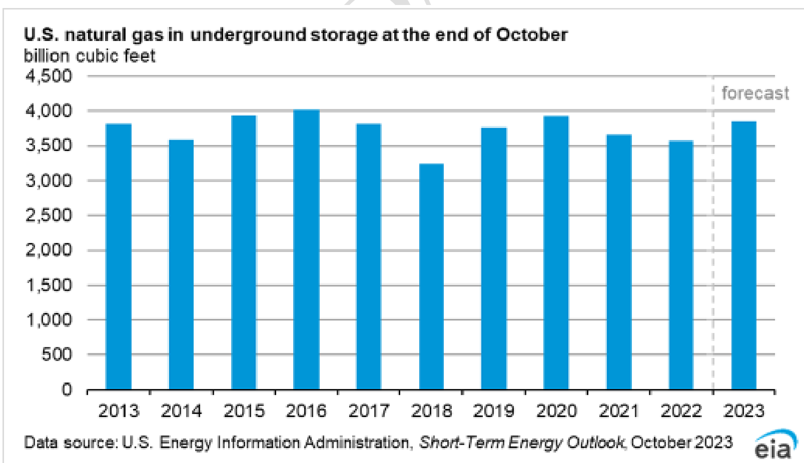
The United States exported the most LNG of any country in the first half of 2023, 10% above its average for all of 2022. Though they fell in 3Q23, the EIA expects LNG exports to increase in 4Q23 and continue into 2024, averaging 12.7 Bcf/d for the first nine months of 2024. In 4Q24, the EIA expect LNG exports to approach 15.0 Bcf/d due to three new export projects set to begin operations and expand U.S. export capacity.

The EIA believes U.S. natural gas pipeline exports, which go to both Canada and Mexico, will increase 9% this year (0.7 Bcf/d) from last year, averaging 9.0 Bcf/d for all of 2023. Pipeline exports to Mexico reached a new record in June and have remained high throughout the summer. The EIA expects natural gas pipeline exports to Mexico to continue increasing as pipeline projects in Mexico are completed and demand in Mexico's electric power sector rises.

U.S. natural gas imports in the EIA forecast decline by 6%, or 0.5 Bcf/d, in 2023 compared with 2022. The decline is driven by warmer winter weather in the northern United States, resulting in less natural gas imported from Canada to meet space-heating demand.



For storage, the EIA forecasts U.S. natural gas in underground storage to total 3,854 billion cubic feet (Bcf) at the end of October—the end of summer injection season and the start of winter heating season—6% more than the five-year average (2018—2022). They believe natural gas inventories will increase by about 360 Bcf in October due to a combination of U.S. dry natural gas production growing to nearly 105 Bcf/d and overall U.S. demand for natural gas declining as seasonal temperature patterns emerge in October. Natural gas inventories began the injection season with a 19% surplus to the five-year average. However, for 12 of the past 13 weeks, net injections into U.S. underground storage have been below the five-year average, dropping storage inventories closer to the five-year average. The forecast shows the most U.S. natural gas inventories entering the winter heating season since 2020 and the fourth-most in the past 10 years.



Oil Price Projections

- Buttonwood has researched West Texas Intermediate oil, as well as natural gas price projections through the EIA and year-end NYMEX futures pricing as of 10/24/23.

Price Forecasts					
	WTI Crude Oil ($/Barrel)				
Source	**2023**	**2024**	**2025**	**2026**	**2027**
EIA	75.59	90.91	-	-	-
NYMEX (YE)	83.74	76.80	72.44	69.12	66.44
	Natural Gas ($/million BTU)				
Source	**2023**	**2024**	**2025**	**2026**	**2027**
EIA	2.61	3.23	-	-	-
NYMEX (YE)	3.32	4.22	4.62	4.60	4.54

Expected Pricing Adjustments

- Premiums and discounts are often paid based on the quality of hydrocarbon extracted. Buttonwood has assumed the following differentials:
  - Oil to realize WTI pricing less $3.
  - Natural gas to sell at a premium.
  - Natural Gas Liquids (NGLs) to price at 25% of WTI pricing.

The table below presents the expected pricing adjustments to market prices observed by Buttonwood. Natural Gas is not changed. Please note that energy prices are notoriously variable, and these price expectations may, and likely will, differentiate from those prices that actually occur in the given time periods.

Pricing Adjustment Output (NYMEX as of 10/24/23)							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
WTI Price	83.74	76.80	72.44	69.12	66.44	64.19	62.25
WTI - $3 (Oil)	80.74	73.80	69.44	66.12	63.44	61.19	59.25
NGL Price (25% of WTI)	20.94	19.20	18.11	17.28	16.61	16.05	15.56
Natural Gas	3.32	4.22	4.62	4.60	4.54	4.47	4.51

- With projected extraction costs ranging from $46/bbl to $52/bbl, the projected WTI pricing range shown above, if realized, suggests that the Partnership will potentially receive pricing for production above its breakeven extraction costs.
- However, future extraction pricing per barrel may vary dramatically up or down in the future. While $46/bbl to $52/bbl represents a current projected range for Delaware and Midland wells, this extraction cost may drop notably as production efficiencies are realized or rise above current levels if the wells require ongoing treatment to boost production.
- Overall, projections indicate that oil pricing may trend down over the next 5+ years, highlighting the importance of investors reaching payout on a potential investment in this program as quickly as possible.

Historical Oil Pricing

As shown in the chart below[5], WTI pricing has ranged from a low of \$16.50/bbl in Q2 2020 to a high of \$115/bbl in Q2 2022. Pricing in the range of current breakeven extraction pricing was last realized in late 2020/early 2021.

Site Visit

The Partnership's assets had not been acquired at the time Buttonwood completed its review. As such, a site visit was not conducted as part of the program level review.

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Operating Considerations and Allocations

Drilling, Allocations, Authorization for Expenditure

Drilling Cost Structure

Cost plus 10.0%

- See Drilling Cost Considerations below for more detail.

Net Revenue Interest and Working Interest

The working interest and associated Net Revenue Interest (NRI) applicable to the Fund will be determined by the investment made once capital has been raised. Buttonwood has reviewed details on several wells that are representative of the wells often invested in by the Sponsor. For these representative wells, the full 8/8ths NRI was 75.0% after the typical

[5] Chart as of 11/09/2023.

royalties in place. For a well with an 8/8ths NRI of 75%, the Partnership's NRI would be 75% of the working interest percentage acquired. For example, if the Fund acquires a 10% working interest, the associated NRI would be 7.5%.

Summary Well Detail

Buttonwood has reviewed well detail representative of the characteristics for the wells the Sponsor often invests in. Summary information on a sampling of these wells has been provided below.

Summary Details					
Drill	**Formation Targeted**	**Vertical Depth (ft)**	**Total Depth (ft)**	**Well Cost**	**Cost per Foot**
Drill 1	Bone Spring	7,642	17,600	$8,300,200	$472
Drill 2	Bone Spring	8,857	18,670	$8,809,300	$472
Drill 3	Bone Spring	7,667	17,520	$8,293,100	$473
Drill 4	Bone Spring	8,638	18,515	$8,798,900	$475
Average		*8,201*	*18,076*	*$8,550,375*	*$473*

- Cost per foot varies significantly across a wide range of variables including location (basin, field, formation, etc.) vertical/lateral lengths, completion requirements, etc. which makes it difficult to state outright whether a cost per foot value (i.e., $309, $515) is a "good" or "competitive" price. However, based on prior programs reviewed by Buttonwood, we can state that the projected cost per foot for the four AFEs reviewed would be considered in-line with other programs reviewed.

Authorization for Expenditure (AFE)

Buttonwood has provided a summary of representative AFEs to provide insight into the cost of wells typically invested in by the Sponsor as well as an estimate of IDC percentages associated with these wells.

Summary Details				
Drill	**Intangible Drilling Costs**	**Tangible Drilling Costs**	**Total Costs**	**IDC as % of Total Cost**
Drill 1	6,605,700	1,694,500	8,300,200	79.58%
Drill 2	7,041,600	1,767,700	8,809,300	79.93%
Drill 3	6,605,600	1,687,500	8,293,100	79.65%
Drill 4	7,041,600	1,757,300	8,798,900	80.03%
Average	6,823,625	1,726,750	8,550,375	***79.80%***

- As noted above, the average well pursued has a cost structure with approximately 80% allocated to IDCs.
- Given the targeted load associated with an investment in this program and the net proceeds potentially invested in wells post-load, the IDCs associated with the Partnership's investment would likely max out at about 70% based on a standard working interest allotment.
- If the Managing GP elects to have the Investor Partners' investment be utilized for the payment of IDCs only, the IDCs could represent as much as 80%-85% of the Investor Partners' investment after payment of front-end costs and fees. In such an arrangement, the Managing GP, (or some other entity) would be responsible for all well-related costs other than the IDCs, to the extent of the Partnership's applicable working interest for the well.

Drilling Cost Considerations	Most oil and gas programs utilize either a "Turnkey" cost arrangement or "Cost Plus" arrangement for their operations. Details on each are provided below: **Turnkey:** With this type of arrangement, the operator is paid a set fee, with the operator paying any costs that exceed the projected budget, but also retaining any funds remaining if the well comes in below budgeted cost. In many turnkey arrangements, actual costs are estimated internally by the operator and then the budget is padded heavily to ensure that a sizeable profit remains for the operator at the end. - This sort of arrangement provides certainty of cost but is occasionally derided for being a "black box" designed to provide potentially outsized profits to the operator. - The profit to the operator in some turnkey structures have been known to total as much as 30%-50% of total cost. **Cost-Plus:** In this cost arrangement, a total budget is estimated with an additional percentage layered on that represents the profit to the operator. For example, in the cost plus 10% arrangement in this program, the operator is paid 10% on top of whatever of the actual costs end up being. - This sort of arrangement provides the benefit of insight into operator profit, while also capping that profit at the stated cost-plus percentage level, but cost certainty pre-drilling is not provided and cost overruns are often absorbed by the drilling partnership and other working interest owners. - One other issue to be aware of within cost plus structures is the use of contingencies. When budgeted, contingency line items are built in to allow for cost overruns without these overruns immediately exceeding the planned budget. However, these contingencies are occasionally utilized as a means of building in additional profits to the operator. For example, in some programs previously reviewed by Buttonwood, contingencies representing as much as 20% of total budget were built into programs. The cost-plus component is then layered on top of the contingency-inflated budget. - As noted above, the Fund will utilize a **Cost-Plus model.** - For Drills 1-4 detailed above**, the contingencies represented 4% of total well cost.** In Buttonwood's opinion, this is a realistic and reasonable contingency allotment.

Additional Operational Considerations	
Gathering and Transport	The infrastructure in place for the gathering and transport of well production will be unknown until the applicable wells have been identified and working interest acquired. - For many programs and wells reviewed by Buttonwood, well oil production is gathered in tank batteries onsite, with transport via truck. Gas production is typically tied to a local pipeline network with available capacity and compression.
Water Disposal	Alongside hydrocarbons, oil and gas wells also produce a notable amount of wastewater which needs to be disposed of by the producer. This disposal is typically accomplished by utilizing an injection well whereby the wastewater is injected into a well specifically drilled or converted for the purpose of water disposal (saltwater disposal-SWD). This water disposal will be a notable consideration given the large

	average amounts produced by Midland and Delaware Basin wells (as much as 10 barrels of water per barrel of oil). The disposal options available and undertaken will be determined by the Operator. Water disposal rates vary based on trucking distance, available injection wells, disposal capacity, etc. but on average, disposal rates in the Permian Basin average $0.50-$1.50 per barrel, representing a potentially significant cost on a per barrel of oil basis. Management has extensive experience with water disposal and owns several disposal assets. As such, management has a clear understanding of the costs associated with water disposal.
Sale of Production	The Operator will control the sale of the Partnership's allocable share of production. The Operator will not be known until specific well shave been identified and working interest acquired. **Hedging Activity** The Partnership may enter into hedging arrangements with respect to a portion of future production. The goal of these hedges is to lock in a range of prices to mitigate price volatility and increase the predictability of cash flows. • These transactions limit potential gains if oil or natural gas prices rise above the maximum price established by the call option and may offer protection if prices fall below the minimum price established by the put option only to the extent of the volumes, then hedged. No hedging activity has been undertaken as of the drafting of this report. Per management, hedging activity is not anticipated.

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Insurance

Coverage

The Partnership will be acquiring working interest in wells falling under an Operator unknown at this time. The applicable insurance will be held by the Operator.

- Buttonwood recommends verifying the insurance coverage once an operator and the applicable wells have been identified. It is also recommended that annual confirmation of insurance effectiveness be verified. This insurance verification will be available through the Sponsor or through Buttonwood's quarterly AIM reports (if sponsor participates in AIM program).

Financial Projections

Forward Looking Projections and Model Review

Buttonwood cautions that accurately projecting returns from oil and gas production can be difficult, even when projecting on a known property with proved reserves. This difficulty in projecting returns over a long-term horizon is predominantly due to variables partially beyond the control of the operator such as fluctuations in flow rates and inconsistent energy prices that can swing dramatically from year to year. While efforts can be made to stabilize flows and hedge production to lock in expected prices, the reality is that variables still introduce themselves over time and long-term hedging of full production is not common among energy producers. The projections to follow have been provided to present several potential return cases for investors across a variety of oil and gas pricing and exit valuation scenarios. These projections are forward-looking and provided for informational and discussion purposes.

Model Review
Buttonwood has thoroughly reviewed the financial projection model prepared by the Sponsor. This review focused on the following:

Use and Reasonableness of Assumptions:

- **Target Assets**: The assets that will be held by the Partnership will not be acquired until capital has been raised. As such, representative acquisition prospects have been utilized for the purpose of generating the financial projection model. The assets utilized for the model are two wells to be drilled by Occidental Petroleum (Oxy). The wells average 11,350 feet in total depth with 10,000-foot laterals and estimated total cost of $13,500,000 on average per well. The assets are reasonable proxies for the acquisition to eventually be made by the Partnership given that they are targeting the Wolfcamp formation, one of the stated targeted formations.
- **Production**: It is important to note that the Oxy project utilized for the projections is a large-scale undertaking envisioning up to 300 wells spread across the Wolfcamp A2 and B benches. Given the targeted maximum capital raise for the Partnership ($10mm), the working interest to be acquired would average just 0.2% for the 200 well Wolfcamp A2 project and 0.2% for the 100 well Wolfcamp B project. Projected production volumes are high, but reasonable and reflective of a 300 well program.
- **Pricing:** The Sponsor has evaluated multiple pricing scenarios including: i) strip pricing, ii) 90% of strip, iii) $80/bbl-$3.0/mcf flat pricing, iv) Breakeven $43/bbl-$2.15/mcf flat pricing, v) $60/bbl-$2.5/mcf flat pricing and vi) $100/bbl-$3.50/mcf flat pricing. Buttonwood considers the pricing assumptions evaluated to be reasonable and representative of the current and anticipated pricing environment. As noted in the Market Overview section, Buttonwood price projections anticipate WTI oil pricing to decline to a level between $60-$70 barrel over the next 5 years. As such, in the financial projections evaluated by Buttonwood (below) investor return scenarios have been evaluated utilizing oil and gas pricing at the $43/bbl-$2.15/mcf level, $60/bbl-$2.50/mcf level, $80/bbl-$3.0/mcf level, and $100/bbl-$3.50/mcf level to capture potential downside scenarios as well as a potential high price scenario.
- **Expenses:** Expense assumptions are reasonable and inclusive of all appropriate line items including operated expenses as well as non-operated expenses (i.e., taxes). Expense levels are in line with extraction prices per barrel widely seen in the Midland and Delaware Basins.

Functionality and Efficiency of Model:

- Scope: The model is broad in the range of scenarios contemplated and thorough in its ability to capture nuanced changes in variables.
- Function: Buttonwood manually tested multiple formulas on multiple tabs to assess the functionality of the model. This testing is done to identify deficiencies in a model that may lead to unrealistic or inaccurate projections. The model functioned as expected and we are confident the projections generated by the model accurately reflect the various assumptions utilized. However, we caution again that the projections are forward-looking and based on assets that have not been acquired. As such, the projected results are speculative in nature.

Investor Return Projections

Assets Evaluated

As noted in the section above, the projections provided herein are based on assets not yet acquired by the Partnership. While the possibility exists that the same assets evaluated in the projections could be acquired once the Partnership raises capital, it is possible that a different asset(s) will ultimately be acquired. We have provided the detailed projections to follow as the assets that are ultimately acquired (if not the ones utilized for these projections) should, perform similarly given that they will be drilled and operated in the same Delaware and Midland basins by an experienced operator.

Oil Price Scenarios Evaluated

To capture a wide range of potential outcomes and the associated investor returns, Buttonwood has evaluated the following scenarios:

Scenario	Oil Price	Gas Price
Base Case	$80.00/bbl	$3.00/mcf
Reduced Price 1	$60.00/bbl	$2.50/mcf
Reduced Price 2	$43.00/bbl	$2.15/mcf
Price Increase	$100.00/bbl	$3.50/mcf

Exit Value Scenarios Evaluated

The Sponsor has assumed an exit valuation of PV-12 for purposes of the projections. While Buttonwood reviews programs utilizing discount rates as low as PV-10, we also see PV-20 utilized often when evaluating exit pricing for oil and gas. As such, Buttonwood has evaluated each of the pricing scenarios noted above with both PV-12 and PV-20 methodology on exit.

- Buttonwood has provided projected return information across hold periods ranging from an exit in year 3 to an exit in year 10.

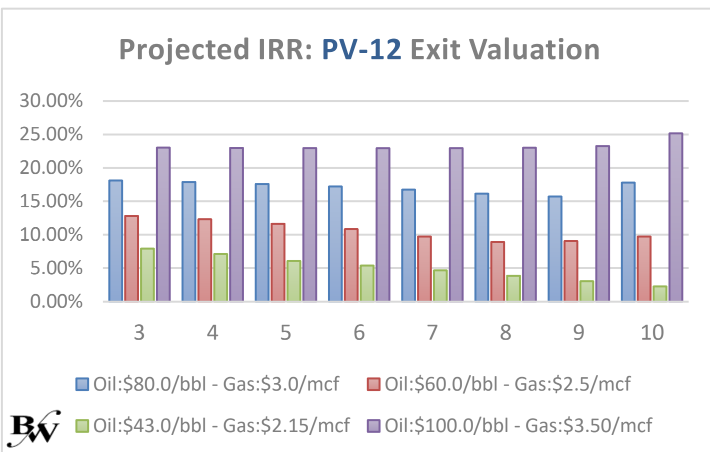
Projected Returns

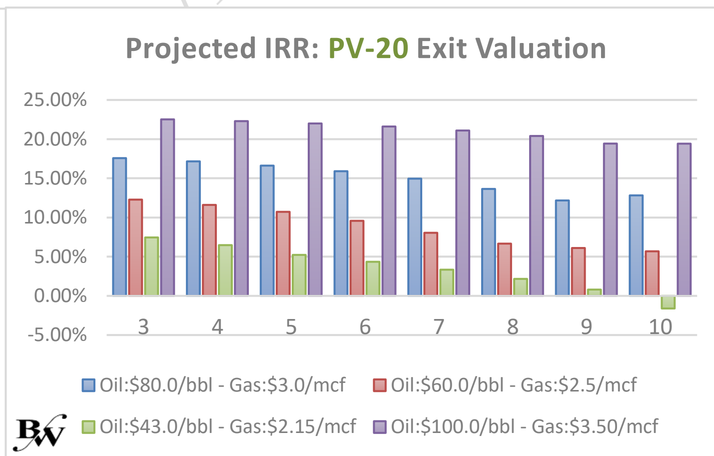
Buttonwood has calculated returns for the various scenarios discussed and presented these returns as 1) IRR, 2) % of Investment and 3) Multiple of Invested Capital (MOIC). **The potential tax benefits received by investors have not been included in the returns summarized below.**

Internal Rate of Return (IRR)

IRR: PV-12 Exit Valuation								
	Exit in year							
	3	4	5	6	7	8	9	10
Oil:$80.0/bbl - Gas:$3.0/mcf	18.11%	17.87%	17.58%	17.21%	16.75%	16.15%	15.71%	17.80%
Oil:$60.0/bbl - Gas:$2.5/mcf	12.81%	12.30%	11.65%	10.82%	9.73%	8.90%	9.03%	9.73%
Oil:$43.0/bbl - Gas:$2.15/mcf	7.93%	7.10%	6.06%	5.40%	4.67%	3.87%	3.04%	2.27%
Oil:$100.0/bbl - Gas:$3.50/mcf	23.03%	22.99%	22.95%	22.93%	22.94%	23.02%	23.25%	25.15%

IRR: PV-20 Exit Valuation								
	Exit in year							
	3	4	5	6	7	8	9	10
Oil:$80.0/bbl - Gas:$3.0/mcf	17.58%	17.16%	16.62%	15.91%	14.96%	13.65%	12.17%	12.82%
Oil:$60.0/bbl - Gas:$2.5/mcf	12.28%	11.61%	10.72%	9.58%	8.05%	6.66%	6.11%	5.69%
Oil:$43.0/bbl - Gas:$2.15/mcf	7.45%	6.48%	5.23%	4.35%	3.34%	2.17%	0.80%	(1.61%)
Oil:$100.0/bbl - Gas:$3.50/mcf	22.52%	22.30%	22.00%	21.61%	21.10%	20.40%	19.43%	19.42%



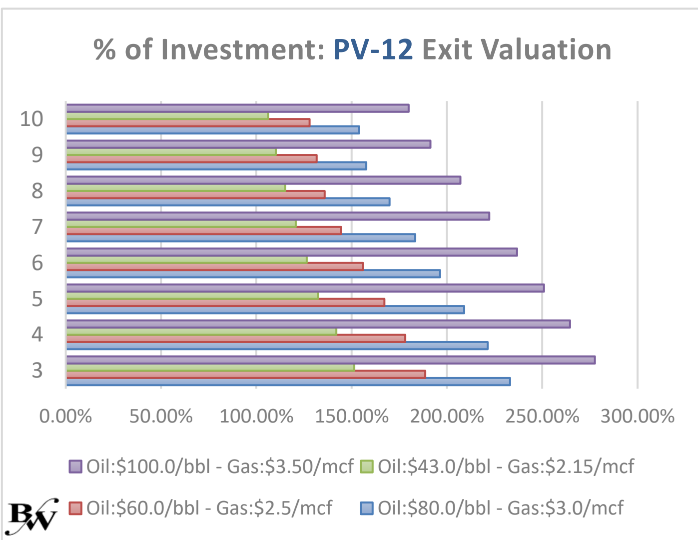


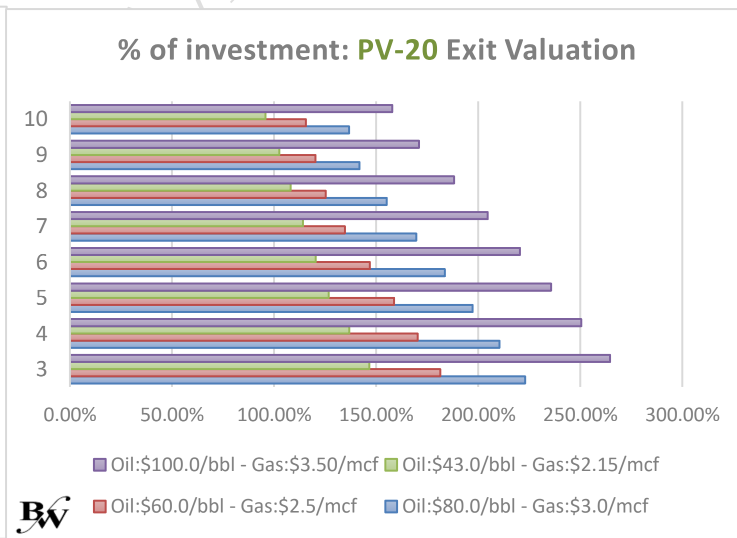
- As shown in the tables and charts above, projected returns calculated by Buttonwood are strong in the base case with a PV-12 calculation at exit, ranging from an IRR of 15.71% up to 18.11% depending on year of exit. As would be expected, returns taper off when utilizing a PV-20 exit valuation as the higher discount rate devalues future cash flows more, although base case returns are still solidly in the mid-teens for IRR. In the down case scenarios of $60 oil and $2.50 gas, projected returns fall into the low teens, high single digits, but are still reasonable across the PV-12 and PV-20 scenarios. Breakeven pricing knocks returns down, even dropping into negative territory for a long-term hold in the PV-20 scenario.
- The potential tax benefits received by investors are not factored into the returns shown above.

% of Investment

% of Investment: PV-12 Exit Valuation								
	Exit in year							
	3	4	5	6	7	8	9	10
Oil:$80.0/bbl - Gas:$3.0/mcf	233.11%	221.35%	209.03%	196.37%	183.35%	169.88%	157.67%	153.91%
Oil:$60.0/bbl - Gas:$2.5/mcf	188.60%	178.12%	167.17%	155.97%	144.49%	135.83%	131.63%	127.93%
Oil:$43.0/bbl - Gas:$2.15/mcf	151.38%	141.97%	132.33%	126.42%	120.66%	115.16%	110.19%	106.18%
Oil:$100.0/bbl - Gas:$3.50/mcf	277.61%	264.57%	250.89%	236.78%	222.20%	207.07%	191.33%	179.90%

% of Investment: PV-20 Exit Valuation								
	Exit in year							
	3	4	5	6	7	8	9	10
Oil:$80.0/bbl - Gas:$3.0/mcf	223.03%	210.45%	197.27%	183.70%	169.70%	155.20%	141.84%	136.76%
Oil:$60.0/bbl - Gas:$2.5/mcf	181.46%	170.37%	158.79%	146.92%	134.74%	125.32%	120.28%	115.60%
Oil:$43.0/bbl - Gas:$2.15/mcf	146.67%	136.85%	126.78%	120.41%	114.16%	108.14%	102.58%	95.80%
Oil:$100.0/bbl - Gas:$3.50/mcf	264.61%	250.52%	235.74%	220.47%	204.66%	188.21%	171.02%	157.92%



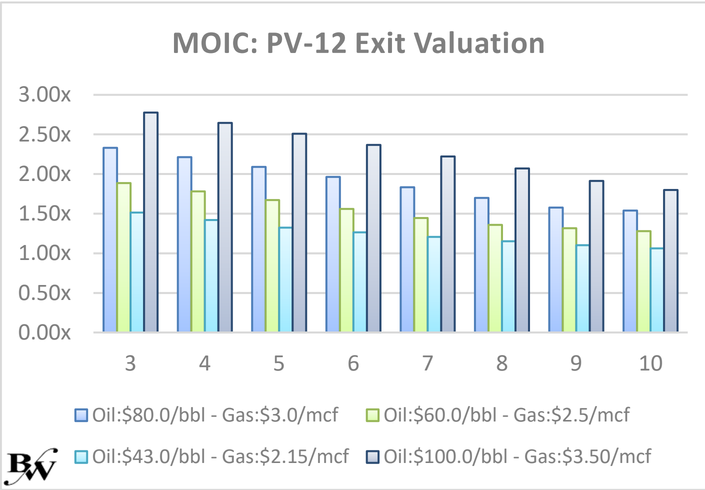


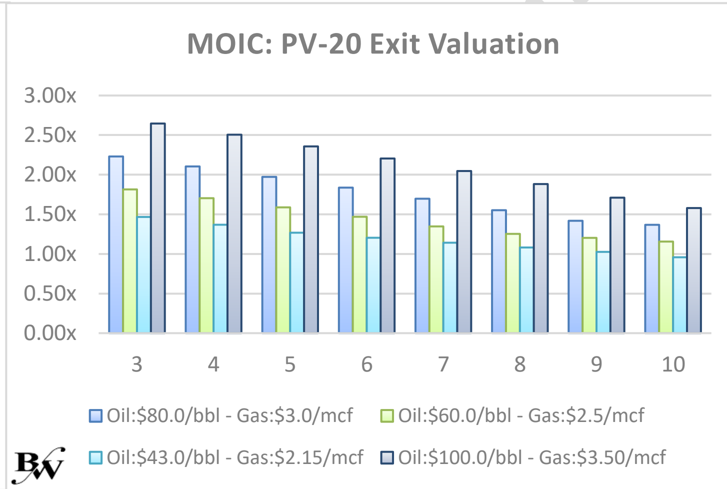
MOIC

MOIC: PV-12 Exit Valuation								
	Exit in year							
	3	4	5	6	7	8	9	10
Oil:$80.0/bbl - Gas:$3.0/mcf	2.33x	2.21x	2.09x	1.96x	1.83x	1.70x	1.58x	1.54x
Oil:$60.0/bbl - Gas:$2.5/mcf	1.89x	1.78x	1.67x	1.56x	1.44x	1.36x	1.32x	1.28x
Oil:$43.0/bbl - Gas:$2.15/mcf	1.51x	1.42x	1.32x	1.26x	1.21x	1.15x	1.10x	1.06x
Oil:$100.0/bbl - Gas:$3.50/mcf	2.78x	2.65x	2.51x	2.37x	2.22x	2.07x	1.91x	1.80x

MOIC: PV-20 Exit Valuation

	Exit in year							
	3	4	5	6	7	8	9	10
Oil:$80.0/bbl - Gas:$3.0/mcf	2.23x	2.10x	1.97x	1.84x	1.70x	1.55x	1.42x	1.37x
Oil:$60.0/bbl - Gas:$2.5/mcf	1.81x	1.70x	1.59x	1.47x	1.35x	1.25x	1.20x	1.16x
Oil:$43.0/bbl - Gas:$2.15/mcf	1.47x	1.37x	1.27x	1.20x	1.14x	1.08x	1.03x	0.96x
Oil:$100.0/bbl - Gas:$3.50/mcf	2.65x	2.51x	2.36x	2.20x	2.05x	1.88x	1.71x	1.58x





Mirroring the trends seen in the IRR analysis, MOIC is respectable across the base case and initial down scenarios, with some scenarios exceeding 2.0x (not including the $100 oil up case). In the breakeven scenario with a longer-term hold, returns potentially drop to a level just sufficient to return capital, although as previously noted, these projected returns do not factor in the potentially significant tax benefits potentially recognized by some investors.

Tax Impact

Tax Impact - Investor

Buttonwood does not provide tax advice to BDs, RIAs, FOs and/or their investors. The commentary and table below provide information on the potential tax benefit available to those investors with the appropriate income to offset, that may be realized from the Intangible Drilling Costs (IDC) allocated to the Partnership's investors. The following table assumes a 37% income tax bracket and provides potential benefit for IDC allocations to investors ranging from 65%-80%.

Income	$800,000	$800,000	$800,000	$800,000
Tax Bracket	37.00%	37.00%	37.00%	37.00%
Tax Liability-pre IDC allocation	$296,000	$296,000	$296,000	$296,000

Investment in Program	$200,000	$200,000	$200,000	$200,000
IDC Allocation	65.00%	70.00%	75.00%	80.00%
First Year Tax Deduction	$130,000	$140,000	$150,000	$160,000
Taxable Income-post IDC allocation	$670,000	$660,000	$650,000	$640,000
New Tax Liability	$247,900	$244,200	$240,500	$236,800
Year 1 Tax Savings	$48,100	$51,800	$55,500	$59,200
Tax Savings as percent of investment	24.05%	25.90%	27.75%	29.60%

- As noted in the table above, the IDC tax benefit associated with oil and gas drilling programs can provide a notable financial benefit to investors as evidenced by the estimated 24.05% - 29.60% benefit as a percentage of investment value. However, depending on if/when the Partnership's assets/working interest are sold, investors need to be aware that they will potentially be subject to recapture of the IDC benefit claimed in year 1 if they do not reinvest in a similar IDC program. See Recapture of IDC Tax Benefit below.
- As noted in the Operating Considerations and Allocations section, given the targeted load associated with an investment in this program and the net proceeds potentially invested in wells post-load, the IDCs associated with the Partnership's investment would likely max out at about 70% based on a standard working interest allotment.
- However, if the Managing GP elects to have the Investor Partners' investment be utilized for the payment of IDCs only, the IDCs could represent as much as 85% of the Investor Partners' investment after payment of front-end costs and fees. In such an arrangement, the Managing GP, (or some other entity) would be responsible for all drilling and well-related costs other than the IDCs, to the extent of the Partnership's applicable working interest for the wells.

Recapture of IDC Tax Benefit

Gain on the sale of a Partnership's natural gas and oil properties may be recaptured as ordinary income to the extent of non-recaptured Section 1231 losses for the five most recent preceding taxable years on previous sales, if any, of such Partnership's natural gas and oil properties or other assets. Deductions for Intangible Drilling Costs and depletion allowances that are incurred in connection with a natural gas or oil property may be recaptured as ordinary income when the property is sold or otherwise disposed of in a taxable transaction by a Partnership (this can be avoided if the investor reinvests in additional IDC projects). The amount of gain recaptured as ordinary income is the lesser of:

- the amounts that were deducted as Intangible Drilling Costs rather than added to basis, plus depletion deductions that reduced the basis of the property, depreciation deductions and certain losses, if any, on previous sales of Partnership assets; or
- the amount realized in the case of a sale, exchange or involuntary conversion or fair market value in all other cases, minus the property's adjusted basis.

- If an investor becomes subject to IDC recapture at ordinary income tax rates, the initial IDC benefit will in effect become a simple deferral of the original tax liability. However, it should be noted that by deferring the tax liability through the IDC benefit, investors theoretically have the opportunity to put more capital to work in the short term while deferring the tax liability initially offset by the IDC benefit.

Depreciation and Depletion

Depletion

The owner of an economic interest in an oil and gas property may claim the greater of percentage depletion or cost depletion on qualified oil and gas properties. Cost depletion for any year is determined by multiplying the number of units (i.e., barrels of oil or Mcf of gas) sold during the year by a fraction, the numerator of which is the cost of the mineral interest and the denominator of which is the estimated recoverable units of reserve available as of the beginning of the depletion period, (for clarity, this calculation is determining how much of the total estimated quantity was sold).

Percentage depletion is a statutory allowance pursuant to which, under current law, a deduction equal to 15% of the taxpayer's gross income from the property is generally allowed in any taxable year, in general not to exceed (i) 100% of the taxpayer's taxable income from the property (computed without the allowance for depletion) or (ii) 65% of the taxpayer's taxable income for the year.

Percentage depletion will be available, if at all, only to the extent that a taxpayer's average daily production of domestic crude oil or domestic natural gas does not exceed the taxpayer's depletable oil quantity or depletable natural gas quantity, respectively. Generally, the taxpayer's depletable oil quantity equals 1,000 barrels and depletable natural gas quantity equals 6,000,000 cubic feet.

Depreciation

Most of the equipment and materials used in drilling wells, including the casing, tubing and bottom hole equipment are salvageable, they do not qualify for treatment as Intangible Drilling Costs. The Partnership will claim depreciation, cost recovery and amortization deductions with respect to its basis in such equipment and materials as permitted by the Tax Code. For property acquired in 2023 the percentage depreciation permitted in the year of acquisition will be 80% with additional 20% reductions for each year thereafter.

Each investor should consult with their own tax counsel to determine what tax benefits may be available from participation in this program. Buttonwood provides no legal or tax advice and the narrative provided above is for discussion purposes only.

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Tax Opinion

Provided By: N/A
Date: N/A

Opinion

No Tax Opinion has been issued in connection with this offering.

It is not unusual for an energy program such as this one to not have a tax opinion in place. However, the following are items that are typically addressed in an energy program tax opinion:

- The Partnership will be treated as a partnership for federal income tax purposes and not as a corporation
- The Partnership will not be considered "publicly traded" within the meaning of Code Section 7704.

- To the extent the Partnership's wells are timely drilled and amounts are timely paid, subject to each partner's election to capitalize and amortize a portion or all of his or her share of the Intangible Drilling Costs, the partners will be entitled to deduct their pro rata share of the Fund's deductible Intangible Drilling Costs, subject to any limitations applicable to the individual partner.
- Each partner's adjusted tax basis in his or her Partnership Interest will be increased by his or her cash capital contribution and each partner initially will be "at risk" to the full extent of his or her cash capital contribution.
- To the extent the Fund's oil and gas properties are held as working interests, Investor Partners who have elected to be treated as GPs, will not be considered a passive activity within the meaning of Internal Revenue Code Section 469 and losses generated while such GP Partnership Interest is so held will not be limited by the passive activity provisions prior to any conversion of GP Partnership Interests to limited partner Partnership Interests. Investor Partners that elect to be treated as limited partners from the outset will be limited to the passive activity rules of Code Section 469.
- Limited partner Partnership Interests will be considered a passive activity within the meaning of Internal Revenue Code Section 469 and losses generated therefrom will be limited by the passive activity provisions.
- The Partnership will not be terminated solely as a result of the conversion of GP Partnership Interests to limited partnership Partnership Interests.
- To the extent provided herein, the partners' distributive share of the Partnership's tax items will be determined and allocated substantially in accordance with the terms of the Agreement of Limited Partnership.
- No gain or loss will be recognized by partners on the payment of their subscriptions to the Partnership.

Fees and Sponsor/Manager Compensation

Fees and Expenses

Use of Proceeds

The table below presents the anticipated uses of the proceeds from this offering assuming a capital raise of $5,000,000 and $10,000,000.

Use of Proceeds	Amount	% of Offering Proceeds	Amount	% of Offering Proceeds	Notes
	$5,000,000 Raise		***$10,000,000 Raise***		
Partnership Investments	$4,400,000	88.00%	$8,850,000	88.50%	
Offering Fees and Expenses	600,000	12.00%	1,150,000	11.50%	*(1)*
Total Uses	5,000,000	100.00%	10,000,000	100.00%	

Note 1: See Offering Expenses table below for more detail.

Fees and Expenses

Offering Expenses

Use of Proceeds	Amount	% of Offering Proceeds	Amount	% of Offering Proceeds	Notes
	$5,000,000 Raise		***$10,000,000 Raise***		
Origination and Management Fee	$400,000	8.00%	$800,000	8.00%	*(1)*
Legal/Professional Fees	100,000	2.00%	200,000	2.00%	
Marketing Fees	50,000	1.00%	100,000	1.00%	
Organization & Offering Fees	50,000	1.00%	50,000	0.50%	
Total Offering Related Fees	**600,000**	**12.00%**	**1,150,000**	**11.50%**	(2)

Note 1: The Origination and Management Fee may be reduced by offsetting commissions paid to FINRA members relating to the sale of the Units or through retrocession payments to investment. Portions of the Origination and Management Fee may be shared with registered investment advisors and exempt fund advisors through retrocession payments with separate disclosure to relevant Subscribers up to the amount paid by such Subscriber in investment advisor fees relating to an investment in the Partnership.

- Of this 8% amount, those amounts not paid out in commission and/or retrocession payments will be retained by the Managing GP as compensation.

Note 2: A potential total of up to 12.0% of offering proceeds, or $600,000 (if $5,000,000 is raised) or up to 11.50% of offering proceeds, or $1,150,000 (if $10,000,000 is raised) may be paid for the benefit of the Managing GP which may include the reimbursement of incurred costs. This amount will include Organization Fees and Costs. This amount may be reduced by commissions paid to FINRA members and retrocession payments to investment advisors, registered and exempt

- Of this 12.0%/11.5% amount, those amounts not paid out in commission and/or retrocession payments will be retained by the Managing GP as reimbursement of amounts already spent relating to the formation of the offering, or as additional compensation.

- At 11.50% - 12.00%, the Company's offering expenses are on the higher end of the average bracket for private placements (9.0% - 12.0%) but effectively in line with average levels for private placement energy programs (10.0% - 13.0%).

Front End Load vs. Capital

The table below presents a calculation of the anticipated front-end load. The front-end load is calculated as the sum of all offering-related fees and expenses, program formation and start-up costs, consulting fees, acquisition/finder's fees, etc. This calculation focuses on up-front fees and expenses and does not include the cost plus 10% that will be payable on the Partnership's wells.

Load Overview	
Front End Load to Equity - $5mm Raise	14.64%
Front End Load to Equity - $10mm Raise	14.16%

The above values include the 12.0% and 11.50% offering related fees and expenses payable on a $5mm and $10mm raise, respectively, plus the 3.0% finder's fee payable to Whitefish Management. The 3% finder's fee is payable on the net proceeds invested, as such, Buttonwood has calculated this fee as 3% of the net $4.4mm from a $5mm raise and $8.8mm net from a $10mm raise.

Overall Fees and Expenses

Pre-Operating Fees	
Organization and Offering	11.50% - 12.00% - *Break down included in the Offering Expenses section*
Finder's Fees	3.0% of invested amount. Estimated at $132,000 - $265,500 for the $5mm and $10mm raise scenarios, respectively.

Operating Fees	
Cost Plus Fees	10% of the cost to drill and develop the wells. Estimated at • $426,800 for a $5mm raise • $858,450 for a $10mm raise The above estimates assume the full amount, net of Pre-Operating fees, is applied to AFE costs relating to the Partnership wells.
Additional Fees	State taxes on production will likely total approximately 4% - 6%, however, this is a tax assessed on production that will be paid to the state.

Post-Operating Fees	
Manager Participation	The Managing GP is partially owned by High Plains Oil, LLC. High Plains Oil, LLC will be a limited partner in the Partnership Wells and is beneficially owned by Jeff Johnson. Jeff Johnson is the Manager of the Managing GP. As such, the Managing GP and affiliates will participate alongside investors in Partnership distributions through its ownership of Partnership LP Units.

The cost-plus fees that will be assessed on the Partnership are average relative to other similar programs. Buttonwood typically sees a cost-plus range of 5% - 15%.

Fees projected to be assessed to the Fund would be considered minimal. Based on a comparison with other similarly structured offerings reviewed by Buttonwood, overall projected fees and expenses are below average.

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Managing GP and Eagle Eye Funds Ownership

High Plains Oil, an entity affiliated by management ownership, will own Fund LP units and will participate alongside investors in distributions in proportion to its percentage interest.

- As with most energy programs, the Managing GP and/or affiliates will receive compensation from certain fees as noted in the Fees and Expenses section above.

Financial Review

Financial Review: Eagle Eye Funds

Eagle Eye Funds is a newly formed entity. As such, financial statements were not available for review.

Financial Review: PB Non-op Drilling LP

PB Non-op Drilling LP is a newly formed entity. As such, financial statements were not available for review.

Other Considerations

Management and Influence

Investor/Partner Rights

Voting
Each Partner may vote, in person or by proxy, with its vote being counted in proportion with the Partner's Partnership Units in matters considered at Partnership meetings with the quorum required for approval of such matters. The **Managing GP** will have seventy-five **(75%)** of the **Partnership's voting interest**.

- The Investor Partners will not have a vote that could affect the Partnership's decisions unless the Managing GP chooses to abstain from voting.

Management

The Managing GP will have the exclusive management and control of all aspects of the business of the Partnership. No Limited Partner or Additional General Partner will have any voice in the day-to-day business operations of the Partnership. The Managing GP is authorized to delegate and subcontract its duties under the Partnership Agreement to others, including entities related to it.

Delegation of Authority

The Partners have elected to delegate to the Managing GP authority to manage, control, administer and operate the property and business of the Partnership. Each Partner agrees that no Partner other than the Managing GP shall have the right to act as an agent of the Partnership or to execute documents on behalf of the Partnership. Further, each Partner agrees that no Partner or group of Partners (including General Partners) shall have the right to act (other than as specifically provided in the Partnership Agreement) to cause the Managing GP on behalf of the Partnership to take any action binding on the Partnership. Still further, each Partner agrees that no Partner or group of Partners may cause a Partner to be authorized to act on behalf of the Partnership without such Partner having become the duly elected and appointed Managing GP. Any Partner who takes action contravening this delegation agrees to indemnify the Partnership and all other Partners from any loss, liability or expense caused by such action.

- This sort of wholesale transfer of authority and control, from investors to the Managing GP is commonplace in energy programs such as this one.

Partnership Reports

Financial

As soon as reasonably practicable after the end of the Partnership's fiscal year, the Managing GP, at the expense of the Partnership, shall cause to be delivered to the Investor Partners such information (including a statement for that year of each Investor Partner's share of the Profits and Losses, Simulated Gain, Simulated Loss, Simulated Depletion and other items of the Partnership) as shall be necessary for the preparation by the Partners of their federal, state, and local income tax returns.

Partnership Progress

The Managing GP shall furnish reports monthly in the form of summaries indicating the status of the drilling and, if applicable, completion of the Wells until drilling and completion activities are completed.

- Buttonwood recommends that any interested parties also view Buttonwood's AIM ongoing quarterly due diligence reports for coverage and commentary on drilling activity, financial analysis, and a host of other pertinent matters relating to this program.

Other

The Managing GP shall, within 10 days after receipt thereof, forward to each Partner a copy of any notice received by the Managing GP or the Partnership of any material default under any material instrument to which the Partnership is a party or which materially affects the assets of the Partnership, and shall report to the Partners any other developments materially affecting the Partnership, its business or assets, as soon as practicable following the occurrence of each such development.

Books and Records

Investor Partners have the right to review the Partnership's books and records during reasonable business hours at the Partnership's principal office. This office is located at:

401 S. Jim Wright Pkwy Suite 109
Fort Worth, TX, 76108

Calling a Meeting
The Managing GP may call meetings of Partners at such times and places as the Managing GP may determine in its sole discretion. Upon request from a majority in interest of the Limited Partnership Unit owners, the Managing GP must call for a Partner meeting to occur within 30 days of the receipt of the request.

- Given the above meetings can only be called by the Managing GP, or by a majority interest of the Limited Partners. The Managing GP and affiliates will control the majority in interest of Limited Partnership Interests. As such, there is no Partnership Agreement mechanism in place for Investor Partners to call a meeting.
- However, The Managing GP shall, upon request from an Additional General Partner or Limited Partner, promptly provide the names and contact information for the Additional General Partner or Limited Partners to an Additional General Partner or Limited Partner who requests it for the purpose of seeking to request a Partner meeting.

Resignation/Removal of Manager

Resignation
Not specified in the PPM and operating docs.

Removal
Investor Partners having rights to more than seventy-five percent (75%) of Distributions by the Partnership to the Investor Partners as a group shall have the right to remove the Managing GP and to elect and substitute a new Managing GP.

- If the Managing GP is removed, its interest in the Partnership will be converted to a limited partner interest.

Note the supermajority (75%) interest required to remove the Managing GP.

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Conflicts of Interest

Conflicts of Interest

Ownership and Management

- The Managing General Partner is partially owned by High Plains Oil, LLC. High Plains Oil, LLC **will be a limited partner** in the Partnership Wells and is beneficially owned by Jeff Johnson.
- The Managing General Partner is partially owned by Crimson Creek Holdings, LLC. Jake Johnson, a beneficial owner of Crimson Creek Holdings, LLC, is a member of Whitefish Management, LLC. Whitefish Management, LLC is the entity responsible for sourcing investment opportunities for the Fund. Whitefish Management will receive the 3% finder's fee as noted in the Fees and Expenses section of the report.

- The Managing GP and its affiliates also engage in significant participations in oil and gas wells operated by other Operators.

Time and Services of Common Management
The managers of the Managing GP and Partnership are also managers and/or owners of other, non-affiliated entities and investment programs. As such, members of management will need to balance the time they allocate to this Partnership with the time spent overseeing and managing other entities and programs.

Program Conflict
Conflicts with other drilling programs and/or energy related programs could give rise to a conflict of interest between the position of the Managing GP as the Managing GP and the position of the Managing GP or one of its Affiliates as general partner or sponsor of such additional programs. In resolving any such conflicts, per the PPM, each partnership will be treated equitably with such other partnerships on a basis consistent with the funds available to the partnerships and the time limitations on the investment of funds. However, no provision has been made for an independent review of conflicts of interest.

Other Services
Any services not otherwise described in this report or in the PPM for which the Managing GP or any of its Affiliates are to be compensated will be embodied in a written contract which describes the services to be rendered and the compensation to be paid.

Legal Representation
Counsel represents the Managing GP. However, in the event of an indemnification proceeding or lawsuit between the Managing GP and a Partner, the Managing GP upon advice of legal counsel may cause the Partnership to retain separate and independent counsel to represent the Partnership in such proceeding.

Please refer to the PPM for additional details and additional notable risks and conflicts of interest.

Joint Operating Agreement

Joint operating agreements were not available for review as the working interest will not be fully identified and acquired until after capital has been raised in the offering.

- Any notable provisions of the JOA will be noted in the Buttonwood AIM reports (provided AIM coverage is in place)

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Legal and Regulatory Review

Legal and Regulatory Review

Regulatory Actions
Per information provided to Buttonwood and based on discussions with management, members of management, affiliates and the Company are not currently involved in, or expecting to be involved in, any regulatory actions that may impact the Company and/or its investors.

Litigation
Per information provided to Buttonwood and based on discussions with management, members of management, affiliates and the Fund are not currently involved in, or expecting to be involved in, any legal matters that may impact the Fund and/or its investors.

- Buttonwood's background review of management, the sponsor and the Fund did not reveal any bad actor concerns or other notable lawsuit or legal considerations.

Management Team

Management Team

Name	Age	Title
S. Jeffrey Johnson	59	Manager of Managing Partner
Richard Loomis	56	VP of Investor Relations and Marketing
Jake Johnson	28	Manager of Managing Partner

Recent Management Changes
- N/A

S. Jeffrey Johnson: *Founder, CEO, Manager of Managing GP.* S. Jeffrey Johnson is the managing member of High Plains Oil, LLC, a private oil and gas company he founded in April 2011. Mr. Johnson manages and owns Epus Global Energy, LLC, a Texas limited liability company, which he founded in 2016. Mr. Johnson served as Chief Executive Officer and in other roles for Circle Star Energy Corp., an OTC-quoted company, from 2011-2015. He was the founder, Chairman and CEO of Cano Petroleum, Inc. from 2004- 2011, initially an OTC-quoted company which moved to the NYSE/Amex in 2005. Mr. Johnson was CEO of Scope Operating Partnership from 1998-2004 and was the founder and CEO of Acumen Resources, Inc. from 1993-1998. From 1989-1993, he was Vice President of Touchstone Capital. Mr. Johnson also previously served on the NYSE/Amex Listed Partnership Counsel.

Over the years Jeff has served with and been a member of numerous industry associations including:
- NYSE/AMEX Listed Company Council

- Independent Petroleum Association of America
- Society of Petroleum Engineers
- Texas Independent Producers and Royalty Owners Association

Richard Loomis: VP of Investor Relations and Marketing. Richard is a seasoned media professional focused on energy, with experience in print, web, video, television, and social media spanning the last 25 years. He has held management roles in sales, marketing, operations, web development and video production. He is in charge of investor relations, marketing, and public relations. Over his career, he has led the start-up of 5 publications, two television series, developed several websites, handled the PR, advertising and public outreach for both public and private companies, interviewed over 500 CEOs and written countless articles on Energy and the politics of energy. Richard is an expert in the development of strategic audiences using traditional media, newer digital strategies, the application of social platforms and newer augmented reality, virtual reality, and artificial intelligence. Richard was also the founding shareholder of a publicly traded oil and gas company that built reserves up to $500 million in the Cook Inlet of Alaska, helped a private L&G company build infrastructure to handle the marine fuels industry and has consulted on major pipeline infrastructure projects. Ultimately helping to secure over a half a billion in funding.

Jake Johnson: Jake Johnson is the managing member of Crimson Creek Holding, LLC, a Texas limited liability company, which he founded in March 2023. Mr. Johnson is also a member of Whitefish Management, LLC, a private oil and gas company, which was founded in early 2023 to invest in non-operating working interest across the major oil and gas basins in the US, with a primary focus on the Permian Basin. At Whitefish, he is responsible for strategy, acquisitions, forecasting, and portfolio modeling. Prior to Whitefish, Mr. Johnson was the Director of Finance at Accelerate Investment Partners, where he led all finance functions. Accelerate was backed by a large private equity firm based out of New York City and managed over 1,000 wellbores in the Permian Basin. Before joining Accelerate, he worked for Plains All American, a publicly traded midstream company with an enterprise value of ~$18Bn as of September 2023. Mr. Johnson worked directly with C-Suite executives on the Corporate Development/M&A/Strategic Planning team responsible for reservoir engineering and underwriting strategic investment decisions. Mr. Johnson has a degree in Petroleum Engineering from the University of Oklahoma and an MBA from the University of Texas at Austin.

Background Review

	Jeff Johnson	Richard Loomis	Jake Johnson			
Database Searches – *Potentially Adverse*						
Criminal Records	✓	✓	✓			
Lawsuits	✓	✓	✓			
Bankruptcies	✓	✓	✓			
Judgements	✓	✓	✓			
Liens	✓	✓	✓			
Property Foreclosures	✓	✓	✓			
Property Evictions	✓	✓	✓			
Global Watch Lists	✓	✓	✓			
UCC Filings	✓	✓	✓			
Database Searches - *Confirmatory*						
Previous Employers	✓	✓	✓			
Professional Affiliations	✓	✓	✓			

Professional Licenses	✓	✓	✓			
Business/Corporate Affiliations	✓	✓	✓			
Search						
FINRA Review	✓	✓	✓			
SEC Review	✓	✓	✓			
Internet Search						
Google, Edge Searches	✓	✓	✓			
Social Media	✓	✓	✓			

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Service Providers and Consultants

Eagle Eye utilizes a number of outside professional companies and consultants to assist on matters relating to accounting, legal, security, etc. Summary information pertaining to some of these third-party providers that may be utilized at the Fund level is provided below:

Legal, Accounting and Other Professionals	**Legal:** Whitaker Chalk Contact Person: Not Provided Contact Phone: Not Provided Contact Email: Not Provided **Taxes:** Robinson, Burdette, Martin & Seright, LLP Contact Person: Not Provided Contact Phone: Not Provided Contact Email: Not Provided **Accounting:** SkyGroup Contact Person: Rachell Davis Contact Phone: Not Provided Contact Email: Not Provided
Banking	**Firm Bank:** Origin Bank Contact Person: Not Provided Contact Phone: Not Provided Contact Email: Not Provided **Product Business Bank:** Origin Bank Contact Person: Not Provided Contact Phone: Not Provided Contact Email: Not Provided

Service Providers	**Compliance Consultant:** NAV Consultants Contact Person: Not Provided Contact Phone: Not Provided Contact Email: Not Provided
Information Security and Cybersecurity	**IT & Cybersecurity:** IT Protects Contact Person: Not Provided Contact Phone: Not Provided Contact Email: Not Provided

Prior Performance

Overview

Eagle Eye Funds is a newly formed entity and as such does not have a track record of prior investments and/or syndicated offerings to review. However, the Manager of the Managing GP (Jeff Johnson) owns Epus Global Energy, an entity with various interests including saltwater disposal assets. Epus Global has sponsored prior syndicated investment offerings, for more information on the most recent Epus water disposal program offering, view Buttonwood's report available by accessing the APEX platform here.

Additional Information

Comments

PURCHASE OF THE PARTNERSHIP UNITS INVOLVES SIGNIFICANT RISKS. PROSPECTIVE INVESTORS MUST READ AND CAREFULLY CONSIDER THE PRIVATE PLACEMENT MEMORANDUM INCLUDING THAT PORTION ENTITLED "RISK FACTORS." PROSPECTIVE INVESTORS SHOULD CONSULT WITH THEIR OWN LEGAL, TAX AND FINANCIAL ADVISORS PRIOR TO PURCHASING THE UNITS. PURCHASE OF THE UNITS IS SUITABLE ONLY FOR PERSONS OF SUBSTANTIAL MEANS WHO HAVE NO NEED FOR LIQUIDITY IN THEIR INVESTMENT.

IT IS NOT THE INTENTION OF THIS REPORT TO OFFER A RECOMMENDATION TO APPROVE/DISAPPROVE THIS OFFERING, BUT RATHER TO PROVIDE THE BROKER/DEALER WITH THE INFORMATION NECESSARY TO ASSIST IN THEIR DUE DILIGENCE PROCESS.

FINRA 13-26 Compliance	
The following information has been provided to assist Buttonwood's FINRA member clients in meeting their obligations regarding the filing of the updated Private Placement Filer Form implemented by FINRA on May 22, 2021.	
Issuer Name	PB Non-op Drilling LP
Is the Issuer a Reporting Company	No
Issuer Address	401 S. Jim Wright Parkway, Suite 109, Fort Worth, TX 76108-2681
Offering Maximum Raise Amount	$5,000,000 – expandable to $10,000,000
Offering Start Date	October 05, 2023
Type of Security Offered	General Partner and Limited Partner interests
Maximum Sales Commission	Not Defined – See Fees and Expenses
Minimum Investment Amount	100,000
Can minimum be waived	Yes
Does the Offering doc provide an actual or target rate of return	Yes
What exemption from Securities Act of 1933 is being relied on	506(c)
Form D filing date	October 30, 2023
Has Issuer raised capital in last 12 months from any source	No
Is this a Contingency Offering	No
Does Issuer intend to use offer proceeds to make or repay loans to, purchase assets from, or otherwise direct investor proceeds to any officer, director, or executive management of the Issuer, Sponsor, GP, Manager, advisor, or any of the Issuer's affiliates?	No
Has the Issuer, any officer, director or executive management of the Issuer, Sponsor, GP, manager, advisor, or any of the issuer's affiliates been the subject of FINRA, SEC or other federal agency, or state disciplinary actions or proceedings or criminal complaints within the last 10 years?	No

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Documents Reviewed

The following documents, **among others**, were reviewed:

- PPM dated 10/05/2023
- Subscription agreement
- Financial Model based on Oxy 300 well project
- Midland Basin current stats including drill rig activity
- Delaware Basin current stats including drill rig activity
- Sample AFE-Mewbourne 1
- Sample AFE-Mewbourne 2
- Formation certificate-Partnership
- Eagle Eye Funds Presentation
- Management biographical information
- Service provider overview

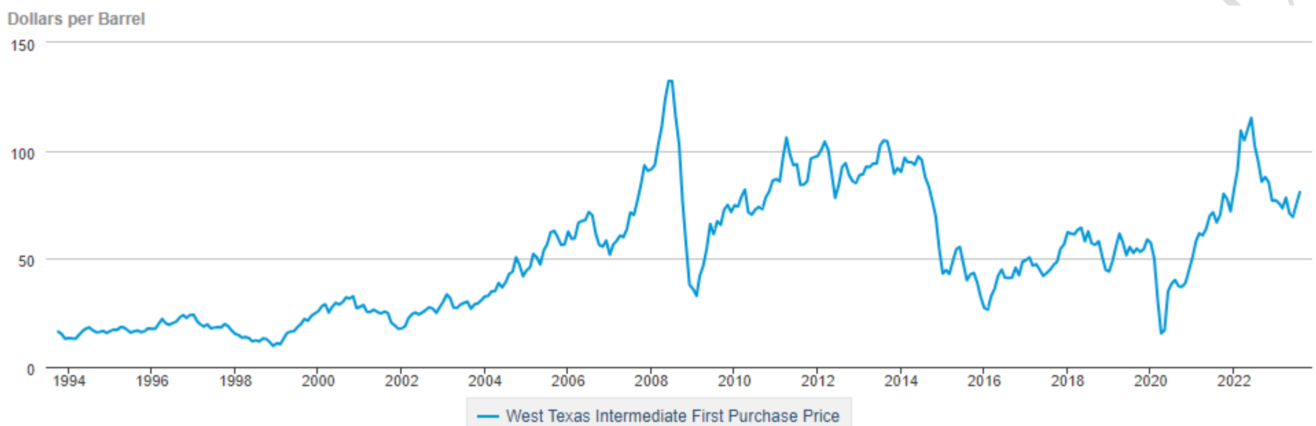
Contact Information

PB Non-op Drilling LP
Attn: Richard Loomis
Eagle Eye Funds, LLC
401 S. Jim Wright Parkway, Suite 109,
Fort Worth, TX 76108-2681
682-316-8777

Appendix A: Commodity Pricing

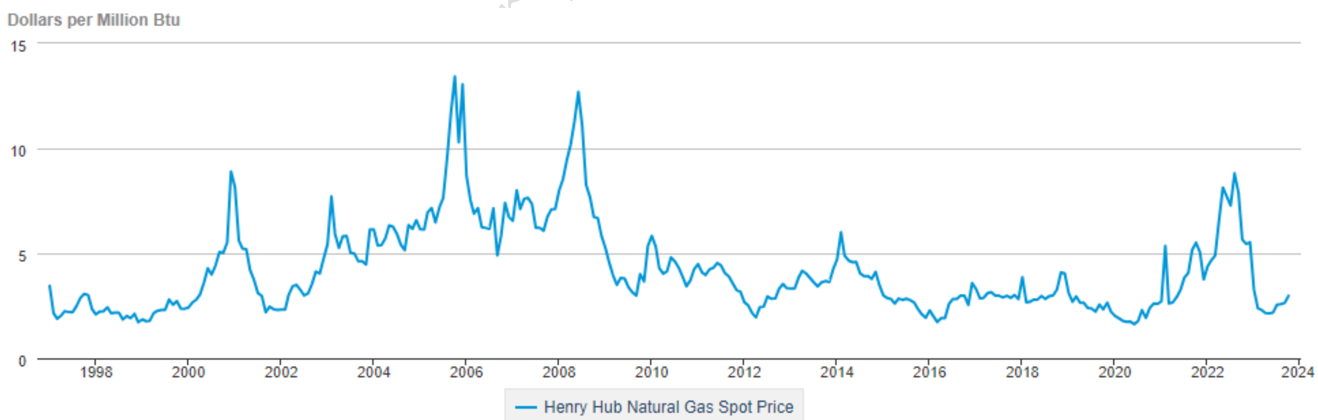
Current Gas and Oil Prices

West Texas Intermediate First Purchase Price



https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F003048623&f=M

Natural Gas Futures Pricing



https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

Gas futures prices are currently trending low around levels on par with some of the lowest marks reached over the last 30 years.

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