OFFERING MEMORANDUM NO._______

PB Non-op Drilling LP

(An Oil and Gas Development Program)

December 7, 2023

50 Units ($100,000 each) totaling
$5,000,000 in Limited Partnership Units and
Additional General Partnership Units

The Managing General Partner has the right to increase the offering to a Maximum of 100 Units ($100,000 each) totaling a Maximum of $10,000,000 in Limited Partnership Units and Additional General Partnership Units

No Minimum

Payment of $100,000 at Subscription

Participation in PB Non-op Drilling LP Units involves a high degree of risk and is suitable only for investors who can afford to lose their entire investment or hold it for a long period of time. Participation in the Program is only being offered to Accredited Investors as defined in Rule 501 of Regulation D of the Securities Act of 1933. See "Risk Factors" and "The Investor Suitability Standards." The entire contents of this memorandum should be carefully read.

Under SEC Rules you may be asked to provide documentation verifying your accredited investor status. Our Subscription Agreement contains a covenant to provide such information when requested. These provisions are required by SEC rules which require taking reasonable steps to verify accredited investor status.

PB Non-op Drilling LP (the "Partnership") is offering fifty (50) (and potentially up to one hundred (100)) Preferred Additional General Partner and Preferred Limited Partnership Units ("Partnership Units") at $100,000 per Partnership Unit for a total offering amount of $5,000,000 (and potentially up to $10,000,000). The Partnership was formed to participate in acquiring non- operating Working Interest in prospective wellbores (and leasehold interest) to be drilled and related leaseholds in the Permian Basin located in West Texas and Eastern New Mexico (the "Partnership Wells"). The Partnership plans to bid on non-operating Working Interest in oil and gas wells to be drilled in the Permian Basin. The Managing General Partner will not operate the wells. The Operator designation will depend on the Partnership winning the bid for the non- operating Working Interest. 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. The Partnership Wells will be sourced from Whitefish Management, LLC. Jake Johnson, a beneficial owner of Crimson Creek Holdings, LLC, an owner of the Managing General Partner, is a member of Whitefish Management, LLC.

The fund administrator will be:

Attn: Investor Services Department
c/o Formidium Corp.
633 Rogers St, Suite 106
Downers Grove, IL 60515
Tel.: +1 630-828-3520
Fax: +1 630-642-5338
E-mail: investor.support@formidium.com

SkyGroup, LLC will perform accounting services. SkyGroup LLC is not affiliated with the Managing General Partner.

This Partnership investment program has the following characteristics:

- Partners will hold their well interests indirectly through the Partnership.
- The $100,000 per Partnership Unit price will be payable in one installment at subscription.
- Investors will have the opportunity to invest as "Limited Partners" or "Additional General Partners." Limited Partners will have their liabilities limited to the amount that they have contractually obligated to pay to the Partnership but will have their US intangible drilling and completion cost allocations treated as passive activity losses. Such losses may be used to offset passive income and Limited Partners will be capped at a $3,000 deduction per year against active income, with carryover of unused losses to future years. Additional General Partners could be liable for the debts of the Partnership but may be able to deduct intangible drilling and completion cost allocations from US Taxes, assuming other conditions are met. But any such debts should be limited to trade creditor debts. 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). Further, as of January 1 in the tax year after at least ninety percent (90%) of the Partnership's capital contributions have been spent, the Additional General Partners may be converted to Limited Partners as the intangible drilling and completion costs passive loss limitation will likely be immaterial beginning in such tax year.
- The Managing General Partner will receive a ten percent (10%) cost plus fee on the actual well or leasehold costs, including the costs of property acquisition, drilling and completion paid to the Operator, pursuant to the Partnership Agreement attached to this Memorandum as Exhibit B. The fee will be paid from the funds raised in this offering. The fee is contingent on the amount raised.
- The Managing General Partner will receive a marketing fee of one percent (1%) of the subscribed funds.
- The Managing General Partner will receive a fee of two percent (2%) of the subscribed funds for legal, accounting, engineering and other professional expenses.
- The Managing General Partner shall receive an origination and management fee of up to eight percent (8%) of the subscribed funds.
- The Managing General Partner shall receive reimbursement of up to $50,000 for organization fees and offering costs.
- The closing date for this offering is March 30, 2024, unless extended for up to six months at the discretion of the Managing General Partner.

The Managing General Partner will not operate the wells. The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest. Investors should understand that a well spud date may depend on circumstances outside an Operator's control, such as the availability of drilling rigs and other equipment, the timing of permits from the Texas Railroad Commission and other governmental entities, the weather, and government-ordered drilling moratoriums.

The Managing General Partner might not receive optimal pricing if it seeks to sell the Partnerships' Working Interest in the Partnership Wells. There may be a valuation discount per Working Interest percentage if the Partnership sells interest in a Partnership Well separately versus tagging along with the Operator's sale of the entire well or leasehold. Subscribers should anticipate holding their Partnership Units for an extended period of time as the Partnership may be required to hold one or more of its Partnership Well Working Interests for an extended period of time, especially during a period with adverse pricing pressure on oil and gas Working Interests in the Permian Basin.

PB Non-op Drilling LP, a Texas limited partnership (the "Partnership"), was formed on September 1, 2023. The primary investment objective of the Partnership is to participate in the drilling and production of oil and gas in commercial quantities.

This Offering will be sold by the Managing General Partner under the SEC Rule 506. This offering will not be registered with the U.S. Securities and Exchange Commission and the Partnership units sold through this private placement memorandum carry no registration rights.

The minimum investment is one Unit, but that minimum may be waived in the discretion of the Managing General Partner.

IRA Funds.

Tax-qualified accounts, such as IRAs, will generally not be able to benefit from intangible drilling and completion costs and depletion deductions and bonus depreciation deductions. Moreover, the Units may generate unrelated business taxable income ("UBTI") in a tax-deferred account that would cause such accounts to be obligated for taxes on the UBTI even in a tax- deferred account. (But UBTI may be offset by intangible drilling and completion costs and depletion deductions.) Accordingly, the Managing General Partner generally recommends investing using funds sourced from accounts other than IRA or other tax-qualified accounts.

The Tax Cut and Jobs Act

On December 22, 2017, President Trump signed The Tax Cut and Jobs Act, into law. The following is not tax advice. Seek the advice of your own tax advisor.

Bonus Depreciation

New Section 168(k)(2) allows bonus depreciation for any qualified property with a depreciable life of 20 years or shorter. The qualified property with depreciable life of 20 years or shorter may include oil and gas equipment such as tanks, pumps, and pipeline (provided the asset is qualified and has a depreciable life of 20 years or less). Such assets be subject to a temporary bonus depreciation which would result in a pass-through write-off of one hundred percent (100%) of the potential depreciation of such qualified equipment. This results from The Tax Cuts and Jobs Act of 2017 which temporarily enhances bonus depreciation. Under the Act, for qualified assets

(i) with a depreciation schedule of twenty (20) years or less and (ii) placed in service between September 28, 2017, and December 31, 2022 (or by December 31, 2023, for certain property with longer production periods), the first-year bonus depreciation deduction increases to one hundred percent (100%) for both new and used assets placed into service. Beginning in 2023, bonus depreciation is scheduled to be reduced twenty (20) percentage points each year, until it is fully eliminated in 2027.

THIS INVESTMENT IS SPECULATIVE, INVOLVES A HIGH DEGREE OF RISK AND DILUTION, AND SHOULD BE PURCHASED SOLELY BY THOSE PERSONS WHO CAN AFFORD TO LOSE THEIR ENTIRE INVESTMENT.

		Units - 50	
Assuming $5,000,000 Subscription Amount	**Amount**	**Percentage**	**Per Unit**
Subscription Amount	$5,000,000	100.0000%	$100,000
Less Organizational Costs	$50,000	1.0%	$1,000
Estimated Proceeds to Operations	$4,950,000	99.0%	$99,000

CIRCULAR 230 DISCLOSURE: PURSUANT TO U.S. TREASURY DEPARTMENT REGULATIONS, YOU ARE ADVISED THAT UNLESS OTHERWISE EXPRESSLY INDICATED, ANY FEDERAL TAX ADVICE CONTAINED IN THIS COMMUNICATION, INCLUDING ATTACHMENTS AND ENCLOSURES, IS NOT INTENDED OR WRITTEN TO BE USED, AND MAY NOT BE USED FOR THE PURPOSE OF (1) AVOIDING TAX-RELATED PENALTIES UNDER THE INTERNAL REVENUE CODE, OR (2) PROMOTING, MARKETING, OR RECOMMENDING TO ANOTHER PARTY ANY TAX-RELATED MATTERS ADDRESSED HEREIN.

NEITHER THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION ("SEC") NOR ANY REGULATORY AUTHORITY OF ANY OTHER JURISDICTION HAS PASSED ON THE MERITS OF OR GIVEN ITS APPROVAL TO THE UNITS OFFERED OR THE TERMS OF THIS OFFERING, NOR DOES IT PASS UPON THE ACCURACY HEREOF OR COMPLETENESS OF ANY OFFERING CIRCULAR OR OTHER SELLING LITERATURE. ANY REPRESENTATION TO THE CONTRARY IS UNLAWFUL. THESE SECURITIES ARE OFFERED HEREBY PURSUANT TO AN EXEMPTION FROM REGISTRATION WITH THE SEC AND APPLICABLE SECURITIES REGULATORY AUTHORITIES OF OTHER JURISDICTIONS. NEITHER THE SEC NOR ANY REGULATORY AUTHORITY OF ANY OTHER JURISDICTION HAS MADE AN INDEPENDENT DETERMINATION THAT THE SECURITIES OFFERED HEREUNDER ARE EXEMPT FROM REGISTRATION.

The date of this Offering Memorandum is December 7, 2023.

ADDITIONAL INFORMATION

DURING THE COURSE OF THIS OFFERING AND PRIOR TO SALE, EACH OFFEREE MAY ASK QUESTIONS OF, AND RECEIVE ANSWERS FROM THE MANAGING GENERAL PARTNER CONCERNING THE TERMS AND CONDITIONS OF THIS OFFERING, PROVIDED THE INFORMATION IS REASONABLY AVAILABLE. IN ADDITION, EACH OFFEREE WILL BE ENTITLED TO OBTAIN

ADDITIONAL INFORMATION FROM THE MANAGING GENERAL PARTNER WHICH THEY BELIEVE TO BE MATERIAL TO A DECISION TO INVEST IN THE UNITS (INCLUDING ADDITIONAL INFORMATION TO VERIFY THE ACCURACY OF THE INFORMATION CONTAINED IN THIS MEMORANDUM) TO THE EXTENT THE MANAGING GENERAL PARTNER POSSESSES SUCH INFORMATION OR CAN ACQUIRE IT WITHOUT UNREASONABLE EFFORT OR EXPENSE. SUCH ADDITIONAL INFORMATION AND ALL DOCUMENTS RELATING TO THIS INVESTMENT WILL BE MADE AVAILABLE TO THE OFFEREE UPON REQUEST TO THE MANAGING GENERAL PARTNER, PB NON-OP DRILLING GP, LLC, 401 S. JIM WRIGHT FREEWAY, SUITE 109, FORT WORTH, TX 76108-2681, (682) 316-8777.

The Managing General Partner reserves the right to extend, withdraw or modify this offering and return the amounts tendered prior to issuing the Units to Partners. This offering may be withdrawn at any time before the termination of this offering and is specifically made subject to the terms described in this Memorandum. The Managing General Partner specially reserves the right to reject any subscription tendered.

PROSPECTIVE INVESTORS ARE NOT TO CONSTRUE THE CONTENTS OF THIS MEMORANDUM OR ANY PRIOR OR SUBSEQUENT COMMUNICATIONS FROM THE PARTNERSHIP OR ITS AGENTS AS LEGAL OR TAX ADVICE. EACH INVESTOR SHOULD CONSULT HIS OR HER OWN LEGAL AND TAX ADVISORS AS TO THE LEGAL, TAX AND BUSINESS RAMIFICATIONS RELATED TO AN INVESTMENT IN THE UNITS.

THIS MEMORANDUM CONTAINS A SUMMARY OF CERTAIN PROVISIONS OF THE PARTNERSHIP AGREEMENT, BUT REFER TO THE PARTNERSHIP AGREEMENT, A COPY OF WHICH IS ATTACHED AS EXHIBIT B, FOR COMPLETE INFORMATION CONCERNING THE PARTNERS' RIGHTS AND OBLIGATIONS. THE MEMORANDUM INCLUDES SIGNIFICANT ASSUMPTIONS. NO WARRANTY OF SUCH ASSUMPTIONS IS EXPRESSED OR IMPLIED HEREBY. THE MANAGING GENERAL PARTNER WILL MAKE AVAILABLE ALL PARTNERSHIP DOCUMENTS RELATING TO THIS MEMORANDUM UPON REQUEST FROM A PROSPECTIVE INVESTOR.

NO PERSON HAS BEEN AUTHORIZED TO MAKE ANY REPRESENTATIONS, OR FURNISH ANY INFORMATION, WITH RESPECT TO THE PARTNERSHIP OR THE UNITS, OTHER THAN THE REPRESENTATIONS AND INFORMATION STATED IN THIS MEMORANDUM, THE PARTNERSHIP DOCUMENTS OR OTHER DOCUMENTS, OR OTHER INFORMATION WHICH IS FURNISHED BY THE MANAGING GENERAL PARTNER UPON REQUEST. THE MANAGING GENERAL PARTNER WILL PROVIDE ADDITIONAL INFORMATION REQUESTED BY A PROSPECTIVE INVESTOR FOR EVALUATION PURPOSES IF THIS

INFORMATION IS REASONABLY AVAILABLE. SUCH ADDITIONAL INFORMATION SHOULD ONLY BE RELIED UPON IF FURNISHED IN WRITTEN FORM AND SIGNED BY A PRINCIPAL OF THE MANAGING GENERAL PARTNER. NO CHANGE IN PARTNERSHIP AFFAIRS FROM THE DATE OF THIS MEMORANDUM SHALL BE IMPLIED OR ASSUMED MERELY BY THE DELIVERY OF THIS MEMORANDUM, OR THE SALE OF THE PARTNERSHIP UNITS.

THIS MEMORANDUM CONSTITUTES AN OFFER ONLY TO THE PERSON WHO HAS RECEIVED IT FROM THE PARTNERSHIP. DELIVERY OF THIS MEMORANDUM, OR ANY OTHER DOCUMENTS OR INFORMATION FURNISHED TO AN OFFEREE, TO ANYONE OTHER THAN THE PERSON WHO HAS RECEIVED IT FROM THE PARTNERSHIP IS UNAUTHORIZED.

ANY OFFER TO PARTICIPATE IN THIS PARTNERSHIP SHALL ONLY BE MADE TO ACCREDITED INVESTORS AS DEFINED BY SEC RULE 501(a) UNDER THE SECURITIES ACT OF 1933 BY THE MANAGING GENERAL PARTNER WITHOUT ENGAGING IN ANY ADVERTISEMENT, ARTICLE, NOTICE, OR OTHER COMMUNICATION PUBLISHED IN ANY NEWSPAPER, MAGAZINE, OR SIMILAR MEDIA OR BROADCAST OVER TELEVISION, RADIO, OR THE INTERNET OR THROUGH A SEMINAR OR MEETING WHOSE ATTENDEES HAVE BEEN INVITED BY A GENERAL SOLICITATION OR GENERAL ADVERTISING.

THE PURPOSE OF THIS MEMORANDUM IS TO PROVIDE THE PROSPECTIVE INVESTOR WITH THAT INFORMATION WHICH THE MANAGING GENERAL PARTNER, ON BEHALF OF THE PARTNERSHIP, BELIEVES IS PERTINENT TO AN INFORMED INVESTMENT DECISION. THE MANAGING GENERAL PARTNER RECOGNIZES THAT ADDITIONAL INFORMATION MAY BE NEEDED BY THE PROSPECTIVE INVESTOR TO FORM AN INVESTMENT DECISION. THEREFORE, EACH PERSON CONSIDERING THIS OFFER IS ENCOURAGED TO ASK FOR MORE INFORMATION FROM THE MANAGING GENERAL PARTNER. REQUESTS FOR FURTHER INFORMATION SHOULD BE MADE TO THE MANAGING GENERAL PARTNER, AND SUCH INFORMATION SHOULD ONLY BE RELIED UPON WHEN FURNISHED IN WRITTEN FORM AND SIGNED BY A DULY AUTHORIZED REPRESENTATIVE OF THE MANAGING GENERAL PARTNER.

THIS MEMORANDUM DOES NOT CONSTITUTE AN OFFER OR SOLICITATION IN ANY STATE OR OTHER JURISDICTION IN WHICH SUCH OFFER OR SOLICITATION IS NOT AUTHORIZED.

BECAUSE THE UNITS HAVE NOT BEEN REGISTERED OR QUALIFIED UNDER ANY STATE OR FEDERAL SECURITIES LAWS OR THE LAWS OF ANY NATION, THERE WILL BE NO PUBLIC MARKET FOR THEM. ACCORDINGLY, TRANSFERABILITY OF THE UNITS IS RESTRICTED AND INVESTORS MAY NOT BE ABLE TO LIQUIDATE THEIR INVESTMENT QUICKLY OR ON ACCEPTABLE TERMS, IF AT ALL. AN INVESTOR MUST BE PREPARED TO BEAR THE ECONOMIC RISK OF THE INVESTMENT FOR AN INDEFINITE PERIOD OF TIME.

THE UNITS SHOULD BE PURCHASED ONLY AS A LONG-TERM INVESTMENT. SEE "<u>RISK FACTORS</u>."

THE TAX PORTIONS OF THIS MEMORANDUM ARE NOT, AND SHOULD NOT BE CONSTRUED TO BE, TAX ADVICE TO ANY PERSON OR ENTITY INVESTING IN OR CONSIDERING INVESTING IN THIS OFFERING. EACH INVESTOR AND POTENTIAL INVESTOR SHOULD RELY EXCLUSIVELY ON SUCH INVESTOR'S TAX AND FINANCIAL PROFESSIONAL ADVISORS FOR THE RENDITION OF TAX ADVICE IN CONNECTION WITH THIS OFFERING.

GENERAL LEGEND

THESE UNITS OFFERED HEREBY HAVE NOT BEEN REGISTERED UNDER THE LAWS OF THE UNITED STATES OR ANY OTHER NATION, OR ANY POLITICAL UNIT OF THOSE NATIONS AND ARE BEING SOLD IN RELIANCE ON EXEMPTIONS FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT OF 1933 AND SUCH LAWS. THE UNITS ARE SUBJECT TO RESTRICTION ON TRANSFERABILITY AND RESALE AND MAY NOT BE TRANSFERRED OR RESOLD EXCEPT AS PERMITTED UNDER SAID ACT AND SUCH LAWS PURSUANT TO REGISTRATION OR EXEMPTION THEREFROM. THE UNITS HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE U.S. SECURITIES AND EXCHANGE COMMISSION, ANY STATE OR PROVINCIAL SECURITIES ADMINISTRATOR, OR ANY OTHER SECURITIES ADMINISTRATOR OR REGULATORY AUTHORITY, NOR HAS ANY OF THESE REGULATORY AUTHORITIES PASSED ON OR ENDORSED THE MERITS OF THIS OFFERING OR THE ACCURACY OR ADEQUACY OF THE MEMORANDUM. ANY REPRESENTATION TO THE CONTRARY IS UNLAWFUL.

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Separate Subscription Booklet – Subscription Documents

SUMMARY OF THE OFFERING

The following summary only highlights certain portions of the information contained in this Offering Memorandum ("Memorandum"). This summary is qualified in its entirety by reference to the full text of the Memorandum and its exhibits, all of which should be read and understood by prospective investors.

Partnership:	PB Non-op Drilling LP, a Texas limited partnership.
Managing General Partner:	PB Non-op Drilling GP, LLC, a Texas limited liability company (the "Managing General Partner"), whose address is 401 S. Jim Wright Freeway, Suite 109, Fort Worth, TX 76108-2681, (682) 316-8777.
Partnership Wells:	PB Non-op Drilling LP plans to participate in oil and gas wells in the Permian Basin (the "Partnership Wells"). The Partnership will bid on the Partnership Wells non-operating Working Interest. The Managing General Partner will not operate the wells. The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest. 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. The Partnership Wells will be sourced from Whitefish Management, LLC. Jake Johnson, a beneficial owner of Crimson Creek Holdings, LLC, an owner of the Managing General Partner, is a member of Whitefish Management, LLC.
Unit Price Payment Schedule:	The $100,000 per Unit price will be payable at subscription.
Organizational Costs:	The Partnership will reimburse the Managing General Partner for the organizational fees and offering costs paid by the Managing General Partner, estimated to be $50,000.
Other Compensation:	• The Managing General Partner will receive a ten percent (10%) cost plus fee on the actual well or leasehold costs, including the costs of property acquisition, drilling and completion paid to the Operator. The fee is contingent on the amount raised. • The Managing General Partner may receive proceeds from the Partnership, pursuant to the Partnership Agreement attached to this Memorandum as Exhibit B. • The Managing General Partner shall receive a marketing fee of one percent (1%) of the subscribed funds. • The Managing General Partner shall receive a fee of two

percent (2%) of the subscribed funds for legal, accounting, engineering, and other professional expenses.

- The Managing General Partner shall receive an origination and management fee of up to eight percent (8%) of the subscribed funds.
- The Managing General Partner shall receive reimbursement of up to $50,000 for organization fees and offering costs.
- Whitefish Management, LLC shall receive three percent (3%) of the purchase price of the Partnership Wells as a finder's fee.

Partners: The Managing General Partner together with those persons whose Subscriptions to purchase Additional General Partnership Units and Limited Partnership Units offered hereby are accepted by the Managing General Partner of $5,000,000 (50 Units) or, at the Managing General Partners discretion, up to a maximum of $10,000,000 (100 Units) (the "Maximum Subscription Amount") and who are subsequently admitted to the Partnership. The Maximum Subscription Amount includes completion payments. The initial deposit amounts for these Subscriptions shall be $100,000 per Partnership Unit to be paid at the time of Subscription.

Offering Period: The offering period for the Units will terminate on December 31, 2023 (the "Offering Period"), unless extended by the Managing General Partner for any period up to 30 days.

Terms of Subscription: The Subscription Price for each Unit is $100,000 per Unit paid at the time of Subscription.

Subscription Documents: Each subscriber must return to the Managing General Partner a complete and executed set of Subscription Documents with payment of the initial deposit amount of $100,000 per Unit subscribed.

Partnership Objective: The primary investment objective of the Partnership is to drill or rework oil and gas prospects and produce oil and gas in commercial quantities.

Plan of Operation: 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 (see "AFE Costs" below).

Operator: The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest.

Term of the Partnership: The Partnership was formed as a limited partnership under the laws of Texas on September 1, 2023, and will continue until the occurrence of any event causing winding-up as set out in the Partnership Agreement.

Proceeds: The initial subscription payment amount of $100,000 per Unit will be paid to the Partnership account at PB Non-op Drilling LP, 401 S. Jim Wright Freeway, Suite 109, Fort Worth, TX 76108- 2681.

Capitalization: After organizational costs have been paid, the Partnership is estimated to have available funds before commencement of operations in the amount of up to $5,000,000, or $10,000,000 assuming the Maximum Subscription Amount is increased at the Managing General Partner's discretion and received, all of which will be contributed by the Limited Partners and Additional General Partners. The Managing General Partner will provide managerial services and originated the investment opportunity in the Partnership Wells, and it believes that these efforts have an approximate value equal to its stake in the Partnership and the fees it shall receive from the Partnership.

AFE Costs: The Partnership will participate in the Operator's well(s) by paying its share of the expenses pursuant to an Authorization for Expenditures (AFE). The AFE is an estimated budget and costs may exceed the AFE, in which case the Partnership will be billed for such amounts. That bill will be required to be paid within fifteen days. The Partnership anticipates having sufficient capital reserves however, Subscribers may receive future capital calls from the Partnership for operations required by the Operator.

Risk Factors: There are high risks associated with the purchase of a Unit in the Partnership.

Limited Partners and Additional General Partners: Prospective investors may invest in the Partnership as Limited Partners or Additional General Partners. On January 1 of the year immediately following the calendar year of the Partnership with respect to which the Managing General Partner has determined that the at least 90% of funds paid to the Partnership by the Partners as a result of the offer and sale of Units shall have been expended the Units held by the Additional General Partners may be converted to Limited Partner Units, unless the Managing General Partner determines that such conversion at that time would not be in the best interests of the General Partners or the Partnership.

Other Documents: The Managing General Partner will, upon request, furnish copies of other documents which are important to an understanding of the nature of, or an investment in, the Partnership.

Participation in Costs and Revenues

The following table sets forth the percentage allocation of costs and revenues within the Partnership between the Partners and the Managing General Partner:

Participation in Costs & Revenues within Partnership

	Investors	Managing General Manager
Organizational Fees	100.00%	0.00%
Costs and Revenues during the Operational Phase		
AFE Costs	100.00%	0.00%

Plan of Operations

PB Non-op Drilling LP plans to participate in oil and gas wells in the Permian Basin (the "Partnership Wells"). The Partnership will bid on the Partnership Wells non-operating Working Interest. The Managing General Partner will not operate the wells. The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest. 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. The Partnership Wells will be sourced from Whitefish Management, LLC. Jake Johnson, a beneficial owner of Crimson Creek Holdings, LLC, an owner of the Managing General Partner, is a member of Whitefish Management, LLC.

Description of Operator and Present Drilling Prospects

The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest.

Cost of Operations

The Partnership will participate in the Operators' well(s) by paying its share of the expenses pursuant to an Authorization for Expenditures (AFE). The AFE is an estimated budget and costs may exceed the AFE, in which case the Partnership will be billed for such amounts. Subscribers may receive future capital calls from the Partnership for operations required by the Operator. The Managing General Partner will contribute services it believes have an approximate value equal to a ten percent (10%) cost plus fee on the actual well or leasehold costs, including the costs of property acquisition, drilling and completion paid to the Operator.

Compensation and Payments to Limited Partners, Additional General Partner, Managing General Partner Affiliates, and Consultants

The amounts shown below to be paid from subscriptions may have no bearing or relationship to actual costs which may be incurred for certain of the items set forth below. Rather, the amounts being charged the Partnership by the Managing General Partner reflects those costs which the Managing General Partner has determined, in its sole discretion, to constitute appropriate charges, on a non-accountable basis, for the Managing General Partner's expenditure of funds to organize the Partnership and as compensation for the assets being assigned to the Partnership. To the extent such amounts shown are in excess of actual amounts paid by the Managing General Partner, such excess will be considered as compensation to the Managing General Partner.

The following tables are provided to help prospective investors to understand the types and amount of compensation and reimbursements which the Managing General Partner, its Affiliates, and business development intermediaries will receive from the Partnership. All projected use of proceeds allocations are estimates which may vary depending on operational conditions.

Source and Use of Proceeds for $5,000,000 Offering

Source of Funds	**Amount**	**Percentage**
Managing General Partner's Contribution for the Managing General Partner Interest	Services	-
Partners' Capital Contributions	$5,000,000	100.00%
Totals:	$5,000,000	100.00%

Estimated Use of Proceeds[1]	**Amount**	**Percentage Per Partnership Unit**	**Per Partnership Unit Amount**
Organization Fees and Costs	$ 50,000	1.0000%	$ 1,000
Legal, Accounting, Engineer., and other Professional Fees	$ 100,000	2.0000%	$ 2,000
Marketing Fee	$ 50,000	1.0000%	$ 1,000
Origination and Management Fee[2]	$ 400,000	8.0000%	$ 8,000
Partnership Investments[3]	$ 4,400,000	88.0000%	$ 88,000
Total	$ 5,000,000	100.0000%	$ 100,000

[1] A potential total of up to $600,000 or approximately 12% of funds raised from Initial Capital Contributions (assuming $5,000,000 subscription amount) may be paid for the benefit of the Managing General Partner 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 advisers, registered and exempt.

[2] 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 advisers and exempt fund advisers through retrocession payments with separate disclosure to relevant Subscribers up to the amount paid by such

Subscriber in investment adviser fees relating to an investment in the Partnership.

[3] The Partnership Investments are funds which may be used to acquire non-operating Working Interest in prospective wellbores to be drilled (and leasehold interest) in the Permian Basin located in West Texas and Eastern New Mexico and to maintain and develop those assets. Further, from the Partnership Investments, normal geological, engineering, legal, accounting and permitting expenses relating to ongoing operations will be paid.

All figures used are estimates and are subject to adjustment.

Source and Use of Proceeds for $10,000,000 Offering

Source of Funds	**Amount**	**Percentage**
Managing General Partner's Contribution for the Managing General Partner Interest	Services	-
Partners' Capital Contributions	$10,000,000	100.00%
Totals:	$10,000,000	100.00%

Estimated Use of Proceeds[1]	**Amount**	**Percentage Per Partnership Unit**	**Per Partnership Unit Amount**
Organization Fees and Costs	$ 50,000	0.5000%	$ 500
Legal, Accounting, Engineer. and other Professional Fees	$ 200,000	2.0000%	$ 2,000
Marketing Fee	$ 100,000	1.0000%	$ 1,000
Origination and Management Fee[2]	$ 800,000	8.0000%	$ 8,000
Partnership Investments[3]	$ 8,850,000	88.5000%	$ 88,500
Total	$ 10,000,000	100.0000%	$ 100,000

[1] A potential total of up to $1,150,000 or approximately 11.5% of funds raised from Initial Capital Contributions (assuming Maximum Subscription Amount) may be paid for the benefit of the Managing General Partner 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 advisers, registered and exempt.

[2] 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 advisers and exempt fund advisers through retrocession payments with separate disclosure to relevant Subscribers up to the amount paid by such Subscriber in investment adviser fees relating to an investment in the Partnership.

[3] The Partnership Investments are funds which may be used to acquire non-operating Working Interest in prospective wellbores to be drilled (and leasehold interest) in the Permian Basin located in West Texas and Eastern New Mexico and to maintain and develop those assets. Further, from the Partnership Investments, normal geological, engineering, legal, accounting and permitting expenses relating to ongoing operations will be paid.

All figures used are estimates and are subject to adjustment.

Compensation Paid Assuming Maximum Subscription Amount and Completion of All Partnership Wells

Entity Receiving Compensation	Type of Compensation or Distribution	Amount
Managing General Partner	Organizational fees and offering costs	$50,000
Managing General Partner	A 10% cost plus fee on the actual well or leasehold costs, including the costs of property acquisition, drilling and completion paid to the Operator. The fee is contingent on the amount raised.	Indeterminate
Managing General Partner	Origination and management fee of up to 8% of the subscribed funds	Indeterminate
Managing General Partner	Marketing fee of 1% of the subscribed funds	Indeterminate
Managing General Partner	Fee of 2% of the subscribed funds for accounting, legal, engineering, and other professional expenses	Indeterminate
Managing General Partner	Potential Profit from Partnership Agreement	Indeterminate
Whitefish Management, LLC	3% Finder's fee for Partnership Wells	Indeterminate

All figures used are estimates and are subject to adjustment.

INVESTOR SUITABILITY

Subscribers to this offering of PB Non-op Drilling LP Units must be "Accredited Investors" under SEC Rule 501. Subscribers must be sophisticated, can assess the investment opportunity, have no need for any periodic payments or liquidity from this investment, and, with their spouse, qualify as an "Accredited Investor" under SEC Rule 501. Corporate and other business entities may also subscribe provided they meet the above-described suitability requirements.

Investment in the Partnership Units involves a high degree of risk and is suitable only for persons of financial means who can bear this risk and who have no need for liquidity in this investment. The Offering has not been registered or qualified with, nor has the adequacy or accuracy of this Memorandum been reviewed and passed upon by the U.S. Securities and Exchange Commission or any state or provincial securities administrator. The Offering is being made in reliance on exemptions from registration and qualification requirements. The availability of these exemptions is dependent upon, among other things, the investment intent and qualification of each prospective purchaser.

Representations from prospective purchasers will be reviewed to determine their suitability for investment, and Managing General Partner, in its sole discretion, will have the right to refuse a subscription for any reason. Before Subscribers can purchase a Unit, the Subscriber must represent in writing that (among other things):

A. The Subscriber is acquiring its Unit(s) for investment and not with a view to resale or distribution;

B. The Subscriber can bear the economic risk of losing its entire investment;

C. The Subscriber's overall commitment to investments which are not readily marketable is not disproportionate to its net worth and its investment in PB Non-op Drilling LP will not cause this overall commitment to become excessive;

D. The Subscriber has adequate means of providing for its current needs and personal contingencies and no need for liquidity in its investment in PB Non-op Drilling LP; and

E. The Subscriber understands that PB Non-op Drilling LP can make further capital assessments and the Subscriber has the means to pay such assessments.

PREVIOUS OPERATIONS

PB Non-op Drilling GP, LLC was formed in September 2023. This is its first offering.

GLOSSARY

The following are the definitions of certain terms used in this Offering Memorandum.

Additional General Partner. The holder of a Unit of partnership interest in the Partnership who has been admitted as a general partner.

Affiliate. (i) Any person directly or indirectly controlling, controlled by, or under common control with, another person, (ii) any person owning or controlling ten percent (10%) or more of the outstanding voting securities of another person, (iii) any officer, director, partner of a person, and (iv) if such person is an officer, director or partner, any company for which such person acts in any such capacity.

BBL. The common abbreviation for barrels of oil.

BCF. The common abbreviation for billion cubic feet of natural gas.

Capital Contribution. The total cash contribution that a Partner makes to the Partnership, including assessments.

__Capital Costs__. All the costs incurred by the Partnership in drilling, testing, completing, and equipping the Partnership Wells, and any pipelines built to the Partnership Wells which costs are required to be capitalized for Federal income tax purposes, including any dry hole tangible costs but excluding any intangible completion costs, geological and geophysical costs, and Operating Costs.

__Carried Working Interest__. The Working Interest paid, or carried, for drilling and completion costs relating to the initial drilling and completion operations in a well by one or more other working interest owners.

__Developmental Well__. Oil and gas wells drilled within the proven area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

__Dry Hole__. Any oil and gas well drilled for the purpose of producing oil or gas which is not a Producing Well.

__Exploratory Well__. A well drilled on a geological anomaly not known to produce oil and gas.

__Fiscal Year__. The fiscal year as defined by the Partnership Agreement. Initially the fiscal year will end on December 31, but this can be changed at the discretion of the Managing General Partner.

__General and Administrative Costs__. In respect to any period, all reasonable and customary legal, accounting, geophysical, geological, land, engineering, travel, rent, telephone, and similar costs necessary or appropriate to the conduct of the business of the Partnership, including the Managing General Partner’s management fee.

__Initial Capital Contribution__. The $100,000 per Unit Initial Capital Contribution called for in this Memorandum.

__Leases__. Oil and gas leases granting the lessee the right to a Working Interest.

__Limited Partner__. The holder of a Unit of partnership interest in the Partnership who has been admitted as a limited partner.

__Managing General Partner__. PB Non-op Drilling GP, LLC, a Texas limited liability company, whose address is 401 S. Jim Wright Freeway, Suite 109, Fort Worth, TX 76108-2681, (682) 316-8777.

__MCF__. The common description for a thousand cubic feet of natural gas.

__MMCF.__ The common description for a million cubic feet of natural gas.

__Memorandum__. This Offering Memorandum of the Partnership dated December 7, 2023, pursuant to which the Units are offered for sale.

__Net Revenues__. In respect to any period, the portion of Proceeds more than the Operating Costs and the General and Administrative Costs incurred by the Partnership during such period.

Net Revenue Interest. An interest in an oil and gas property which entitles the owner to a specific portion of the production income from such property.

Offering Period. That period commencing on the date of this Memorandum and ending on March 30, 2024, unless extended for a period up to six months after that date by the Managing General Partner.

Operator. The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest.

Operating Costs. In respect to any period, all cash costs, and expenses of the Partnership in any period, including, without limitation, all costs incurred in connection with the operation and maintenance of the Partnership and the Partnership Wells.

Overriding Royalty Interest. The fractional, undivided interests or rights of participation in the oil or gas, or in the proceeds from the sale of the oil or gas, produced from a specified tract or tracts, which are limited in duration to the terms of an existing lease, and which are not subject to any portion of the expense of development, operation, or maintenance.

Partners. The persons, firms, corporations, and other entities that are admitted into the Partnership as Limited Partners or Additional General Partners in the Partnership plus the Managing General Partner. Reference to a "Partner" means any one of the Partners and the Managing General Partner if the context so requires. No owner of any assigned interest in the Partnership shall be deemed to be a Partner unless and until the assignee has been admitted to the Partnership as a Substitute Partner in accordance with the terms of the Partnership Agreement.

Partnership. PB Non-op Drilling LP, a Texas limited partnership.

Partnership Agreement. The Agreement of Limited Partnership in the form annexed to this Memorandum as Exhibit B, pursuant to which the Partnership will be continued after the admission of Limited Partners into the Partnership.

Partnership Properties. All interests, properties and rights of any type owned by the Partnership.

Partnership Prospects. The oil and gas leases to be acquired by the Partnership, and any substitutions therefore or additions thereto that the Managing General Partner deems advisable or appropriate in the event the development of a specific prospect has, in the sole judgment of the Managing General Partner, become imprudent or inadvisable or needs additional leases for effective development.

Partnership Wells. All oil and gas wells in which the Partnership owns an interest.

Person. Any individual, corporation, partnership, trust, estate, or other entity.

Proceeds. In respect to any period, the aggregate gross cash receipts received by the Partnership from all sources during such period.

<u>Subscription</u>. The execution and delivery to the Managing General Partner of a properly executed set of Subscription Documents by a potential Partner and the tender by such investor of the required cash payment for the Unit(s) which he, she or it wishes to purchase.

<u>Subscription Amount</u>. The total Initial Capital Contributions to be made to the Partnership by subscribers in this offering is up to $10,000,000, assuming Subscriptions for the maximum of 100 Units are accepted by the Managing General Partner prior to the expiration of the Offering Period.

<u>Substitute Partner</u>. The assignee of the Unit(s) of a Partner when both the assignor and assignee of such Unit(s) have satisfied all the requirements of the Partnership Agreement.

<u>PB Non-op Drilling GP, LLC</u>. A Texas limited liability company formed on September 1, 2023, that serves as the Managing General Partner of the Partnership.

<u>Working Interest</u>. An operating interest entitling the holder, at his, her or its expense, to conduct drilling and production operations on the leased property and to receive the net revenues from such operations.

RISK FACTORS

PB NON-OP DRILLING LP UNITS ARE HIGHLY RISKY. PROSPECTIVE PURCHASERS SHOULD CONSIDER THE FOLLOWING FACTORS, AMONG OTHERS, BEFORE SUBSCRIBING, AND ARE URGED TO CONSULT THEIR OWN FINANCIAL, TAX AND LEGAL COUNSEL BEFORE DECIDING TO PURCHASE.

Unlimited Liability for Additional General Partners. Additional General Partners are liable for the obligations of the Partnership on a joint and several basis. This means that they may be liable for the entire amount of obligations of or claims against the Partnership regardless of whether any of the other Partners have similar obligations. If other Partners do not pay their share of obligations and claims, the Additional General Partners could be liable for the shortfall.

Risks Pertaining to Oil and Gas Investments

Speculative Nature of Oil and Gas Activities. Oil and gas drilling is a highly speculative activity marked by many dry holes and mechanical problems. Even completed wells may never show a profit. Poor weather and equipment shortages can also cause delays and added expenses.

Prices of Oil and Gas are Historically Quite Unstable. Global economic conditions, political conditions, and energy conservation have created unstable prices for the purchase of oil and gas. Further, speculative trading on commodity exchanges can cause wild gyrations in pricing. The prices for U.S. oil and gas production can and have materially declined at times in the pricing cycles, which would negatively impact profits to the Partnership. Moreover, since operating wells having fixed monthly costs, the percentage decline in net revenues may well exceed the corresponding percentage decline in oil and gas prices. The prices the Partnership receives for oil and natural gas heavily influences revenue, profitability, cash flow available for capital expenditures and access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices received for production, and the levels of production, depend on numerous factors. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the prices and availability of competitors' supplies of oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and state-controlled oil companies relating to oil price and production controls;
- the price and quantity of foreign imports;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil and natural gas futures contracts;
- the availability, proximity and capacity of gathering and transportation systems for natural gas;
- the availability of refining capacity;
- the prices and availability of alternative fuel sources;
- weather conditions and natural disasters;
- political conditions in or affecting oil and natural gas producing regions, including the Middle East and South America;
- the continued threat of terrorism and the impact of military action and civil unrest;
- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate hydraulic fracturing activities;
- the level of global oil and natural gas inventories and exploration and production activity;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and

- overall worldwide economic conditions.

Lower oil and natural gas prices will reduce the Partnership cash flows, borrowing ability the present value of estimated reserves and ability to make distributions. Oil and gas leases that are not held by production could be at risk of expiring in low price environments. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that the Partnership can produce economically and may affect estimated proved reserves. The present value of future net revenues from estimated proved reserves will not necessarily be the same as the current market value of estimated oil and gas reserves.

The Russian invasion of Ukraine increases pricing risks for oil and natural gas and the potential volatility of the Partnership Wells' net revenue. On February 24, 2022, Russia attacked Ukraine on multiple fronts. Since the commencement of the Ukraine war and the imposition of sanctions the prices of natural gas and oil have spiked in response to the potential unavailability of Russian natural gas and oil. In response, importers of natural gas and oil have been seeking to alternative sources and increased production elsewhere. Further, other importers, such as Germany, have been seeking to reduce their demand, particularly, for natural gas and have been reopening coal power plants. These political and war risks have caused uncertainty in anticipating price levels and price changes in natural gas and oil and thus increased the uncertainty of the anticipated revenue from the Partnership Wells. Subscribers should anticipate high volatility in the price of natural gas and oil obtained by the Operator for the Partnership Wells with corresponding earnings volatility for the Partnership.

Oil and Gas are Priced Globally in U.S. Dollars, thus Creating Currency Risk. The U.S. dollar is the primary reserve currency worldwide and the global currency for oil and gas. This means that the stronger the U.S. dollar, the lower the oil and gas prices. There is a direct inverse correlation. Consequently, while the Partnership does not intend to acquire assets outside of the United States, it will still be indirectly subject to currency risks derived from a strong U.S. dollar. For example, relatively speaking the low prices U.S. dollar prices of oil and gas production in other countries may be offset by the weakening of the local currency. But low prices for domestic U.S. oil and gas production will not be able to be offset by a decline in the local currency compared to the reserve currency because U.S. dollars are the reserve currency.

Oil and Gas Well Drilling and Production Risks – Operations. All drilling and rework activities involve a high degree of risk with exploratory wells presenting a higher degree of risk than developmental wells. Oil and gas drilling hazards include unusual or unexpected formations, pressures or other conditions, blow-outs, fires, failure of equipment, down hole collapses, and other hazards (whether similar or dissimilar to those enumerated). Although AAPL operating agreements require that Operators maintain insurance, the Partnership may suffer losses due to hazards against which it cannot insure or against which it may elect not to insure.

Oil and Gas Well Drilling and Production Risks – Equipment and Materials. The timing of the drilling and completion activity will depend on the timely delivery of the drilling equipment, including the rig and other equipment, and the materials needed to conduct drilling activity. If the necessary equipment and materials are not on site, the Operator's drilling and completion activities will be delayed. Such delays could materially affect the timing of any returns on investment in several ways. First, the delays could increase costs of operations as employees and equipment rentals may need to be paid while waiting on site. Second, such delays could cause a delay in investors receiving returns on investment, thus lowering the effective return on investment. Third, such delays could affect the tax year timing of deductibility of intangible drilling costs, especially if the drilling operations are not commenced by the deadline required under tax law. Fourth, such delays could affect oil and gas lease terms and delay rental payments.

Drilling for oil and natural gas is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us. The Partnership's success could depend, in part, on the success of a drilling program. There is no way to predict in advance of drilling and testing whether any prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable the Partnership to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The Partnership cannot assure you that the analogies drawn from available data from other wells, more fully explored prospects or producing fields will be applicable to current drilling prospects.

The budgeted costs of planning, drilling, completing, and operating wells are often exceeded, and such costs can increase significantly due to various complications that may arise during the drilling and operating processes. The Partnership may incur significant geological and geophysical (seismic) costs before a the commencement of drilling operations – expenses incurred whether a well eventually produces commercial oil and gas quantities or is drilled at all. Exploration wells endure a much greater risk of loss than development wells. The analogies drawn from available data from other wells, more fully explored locations or producing fields may not be applicable to current drilling locations. If actual drilling and development costs are significantly more than the current estimated costs, the Partnership may not be able to continue operations as proposed and could be forced to modify drilling plans accordingly. Drilling for oil and natural gas involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing, and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed, or canceled because of a variety of factors beyond the Partnership's control, including:

- unexpected or adverse drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs, crews, and equipment.

If the Partnership decides to drill a certain location, there is a risk that (i) no commercially productive oil or natural gas reservoirs will be found or produced, (ii) may drill or participate in new wells that are not productive or drill wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. A productive well may become uneconomical if water or other deleterious substances are encountered which impair or prevent the production of oil and/or natural gas from the well. The Partnership's overall drilling success rate or drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in production and revenues and materially harm operations and financial condition by reducing available cash and resources. There is no way to predict in advance of drilling and testing whether any location will yield oil or natural gas in sufficient quantities to recover exploration, drilling or completion costs or to be economically viable. Even if enough oil or natural gas exist, the Partnership may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from the well or abandonment of the well.

The Partnership is subject to contingencies arising from interpretations of federal and state laws and regulations affecting the oil and gas industry. The Partnership is subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues, and other matters. Although the Partnership management intends to comply with the various laws and regulations, administrative rulings, and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, environmental matters are subject to regulation by various federal and state agencies.

The Partnership may rely on successful exploration, development, and acquisitions to maintain reserves and revenue in the future. In general, the volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent that the Partnership conducts successful exploration and development activities or acquires properties containing proved reserves, or both, proved reserves will decline as reserves are produced. The Partnership future oil and natural gas production is, therefore, highly dependent on the Partnership's level of success in finding or acquiring additional reserves. Additionally, the business of exploring for, developing, or acquiring reserves is capital intensive. Recovery in reserves, particularly undeveloped reserves, will require significant additional capital expenditures and successful drilling operations. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. The Partnership's ability to make the necessary capital investment to maintain or expand its asset base of oil and natural gas reserves would be impaired. In addition, the Partnership is dependent on finding partners for exploratory activity. To the extent that others in the industry do not have the financial resources or choose not to participate in exploration activities, the Partnership will be adversely affected.

The Partnership may have accidents, equipment failures or mechanical problems while drilling or completing wells or in production activities, which could adversely affect its business. While the Partnership is drilling and completing wells or involved in production activities, accidents or experience equipment failures or mechanical problems in a well may occur that cause the Partnership to be unable to drill and complete the well or to continue to produce the well according to plan. The Partnership may also damage a potentially hydrocarbon-bearing formation during drilling and completion operations. Such incidents may result in a reduction of production and reserves from the well or in abandonment of the well.

The Partnership's estimated reserves are based on many assumptions that may prove inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of the Partnership reserves. The Partnership intends to obtain periodic reserve estimates covering its properties. No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of the Partnership's reserves which could adversely affect business, results of operations, financial condition, and the Partnership's ability to make cash distributions to shareholders.

To prepare estimates, the Partnership must project production rates and the timing of development expenditures and analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. Although the reserve information contained herein is reviewed by independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise.

Further, the present value of future net cash flows from proved reserves may not be the current market value of estimated oil and natural gas reserves. In accordance with SEC requirements, the Partnership based the estimated discounted future net cash flows from proved reserves on the 12-month average oil and gas index prices, calculated as the un-weighted arithmetic average for the first day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor the Partnership used when calculating discounted future net cash flows for reporting requirements in compliance with the FASB in Accounting Standards Codification, which is referred to as ASC, 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Partnership or the oil and natural gas industry in general.

Seismic studies do not guarantee that hydrocarbons are present or, if present, will produce in economic quantities. The Partnership may use seismic studies to assist with assessing prospective drilling opportunities on current properties, as well as on properties that the Partnership may acquire. Such seismic studies are merely an interpretive tool and do not necessarily guarantee that hydrocarbons are present or if present will produce in economic quantities.

The Partnership is a startup with no operating history. The Partnership is a startup company with all the expected risks of a startup company, including lack of capital, well-funded competitors, and the need to add qualified personnel. If successful, the Partnership will need to expand its infrastructure and personnel to be consistent with the size of the business. The Managing General Partner is newly-formed.

The Partnership will not be the operator on its drilling locations, and, therefore, will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets. The Partnership expects not be the operator on its initial oil and gas properties. As the Partnership carries out its oil and gas property acquisitions and development, it may enter arrangements with respect to existing or future drilling locations that result in a greater proportion of locations being operated by others. As a result, the Partnership may have limited ability to exercise influence over the operations of the drilling locations operated by its partners. Dependence on the operator could prevent the Partnership from realizing target returns for those locations. The success and timing of exploration and development activities operated by its partners will depend on several factors that will be largely outside of the Partnership's control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations of some of drilling locations may cause a material adverse effect on results of operations and financial condition.

Most of the Partnership's growth is anticipated to come through acquisitions, and failure to identify or complete future acquisitions successfully could reduce earnings and hamper growth. The Partnership may be unable to identify properties for acquisition or to make acquisitions on terms that are economically acceptable. There is intense competition for acquisition opportunities in the oil and gas industry. Competition for acquisitions may increase the cost of, or cause the Partnership to refrain from, completing acquisitions. Its ability to grow through acquisitions will require continued investment in operations, financial and management information systems and to attract, retain, motivate, and effectively manage employees. The inability to manage the integration of the merger or future acquisitions effectively could reduce focus on subsequent acquisitions and current operations and could negatively impact results of operations and growth potential. The Partnership's financial position, results of operations and cash flows may fluctuate significantly from period to period, because of the completion of significant acquisitions during periods. If the Partnership is not successful in identifying or acquiring any material property interests, earnings could be reduced, and growth could be restricted.

The Partnership may engage in bidding and negotiating to complete successful acquisitions. It may be required to alter or increase substantially its capitalization to finance these acquisitions using cash on hand, the issuance of equity securities, the sale of production payments, the sale of nonstrategic assets, the borrowing of funds or otherwise. Furthermore, the Partnership's decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which the Partnership employees are familiar may impact productivity in such areas.

The Partnership may seek to acquire oil and gas properties subject to bankruptcy actions which may result in few or no remedies against sellers. Normally when a party purchases an oil and gas property, the seller makes representations and warranties about the properties being sold. If the Partnership seeks to acquire oil and gas properties under a bankruptcy court's supervision, the oil and gas property will be delivered as is, with no representations or warranties. But the properties will also be delivered by the bankruptcy court free and clear of all liens and potential liens, which is a common cause of violations of representations and warranties.

The Partnership may purchase oil and natural gas properties with liabilities or risks that the Partnership did not know about or that the Partnership did not assess correctly, and, as a result, could be subject to liabilities that could adversely affect results of operations. Before acquiring oil and natural gas properties, the Partnership estimates the reserves, future oil and natural gas prices, operating costs, potential environmental liabilities, and other factors relating to the properties. However, such review involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, the Partnership may not discover all existing or potential problems associated with the properties being purchased. This is a special risk for oil and gas properties under bankruptcy court supervision. The Partnership may not become sufficiently familiar with the properties to assess fully its deficiencies and capabilities. The Partnership does not generally perform inspections on every well or property, and therefore may not be able to observe mechanical and environmental problems even when an inspection is conducted. The seller may not be willing or financially able to give contractual protection against any identified problems, and the Partnership may decide to assume environmental and other liabilities in connection with properties acquired. Indeed, properties acquired through bankruptcy court processes will be acquired as is with no protections against potential problems other than liens. If the Partnership acquires properties with risks or liabilities that were unknown or not assessed correctly, financial condition, results of operations and cash flows could be adversely affected as claims are settled and cleanup costs related to these liabilities are incurred. Given the limited due diligence and time opportunities in assessing properties under the supervision of a bankruptcy court, these risks may be increased when acquiring properties from bankrupt sellers.

The marketability of the Partnership's production will be dependent upon oil and natural gas gathering and transportation facilities owned and operated by third parties, and the unavailability of satisfactory oil and natural gas transportation arrangements will have a material adverse effect on revenue. The unavailability of satisfactory oil and natural gas transportation arrangements may hinder the Partnership's access to oil and natural gas markets or delay production from wells. The availability of a ready market for the Partnership's oil and natural gas production depends on several factors, including the demand for, and supply of, oil and natural gas and the proximity of estimated reserves to pipelines and terminal facilities. The Partnership's ability to market its production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Failure to obtain these services on acceptable terms could materially harm the Partnership's business. As a result, the Partnership may be required to shut-in wells for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. If that were to occur, the Partnership would be unable to realize revenue from those wells until production arrangements were made to deliver production to market. Furthermore, if the Partnership were required to shut-in wells the Partnership might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain the Partnership's leases. The disruption of third-party facilities due to maintenance and/or weather could negatively impact the Partnership's ability to market and deliver the Partnership's products. These third parties' control when or if such facilities are restored and what prices will be charged. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect the Partnership's ability to produce, gather and transport oil and natural gas.

Hedging transactions or the lack thereof, may limit the Partnership's potential gains and could result in financial losses. To manage the Partnership's exposure to price risk, from time to time, the Partnership may enter hedging arrangements with respect to a portion of future production. The goal of these hedges are 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.

In addition, hedging transactions may expose the Partnership to the risk of financial loss in certain other circumstances, including instances in which production is less than expected or the counterparties to put and call option contracts fail to perform under the contracts.

Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the contracts. The Partnership is unable to predict sudden changes in a counterparty's creditworthiness or ability to perform under contracts. Even if the Partnership does accurately predict sudden changes, ability to mitigate that risk may be limited depending upon market conditions.

Furthermore, there may be times when the Partnership may have not hedge production when, in retrospect, it would have been advisable to do so. Decisions as to whether and what production volumes to hedge are difficult and depend on market conditions and forecast of future production and oil and gas prices, and the Partnership may not always employ the optimal hedging strategy. The Partnership may employ hedging strategies in the future that differ from those used in the past, and neither the continued application of current strategies nor use of different hedging strategies may be successful.

On April 27, 2012, the SEC and the CFTC issued final rules defining "Swap Dealer," "Security-Based Swap Dealer," "Major Swap Participant," "Major Security-Based Swap Participant" and "Eligible Contract Participant." These definitions have end-user exceptions. To the extent that the Partnership uses swaps to hedge its risks, it will attempt to comply with the end-user and size exceptions from these definitions. If the Partnership is unsuccessful in qualifying for such exceptions in any swap transaction, it may be required to maintain substantial financial reserves relating to its swap transactions and may be required to register with the SEC or CFTC as a swap dealer or participant.

Unless the Partnership replaces its oil and natural gas estimated reserves, its estimated reserves and production will decline, which would adversely affect its business, financial condition, and results of operations. Once the Partnership acquires oil and gas properties, it must conduct successful development, exploitation and exploration activities or acquire properties containing estimated proved reserves, else its estimated proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Estimated future oil and natural gas reserves and production, and therefore cash flows and income, are highly dependent on the Partnership's success in efficiently developing and exploiting current estimated reserves and economically finding or acquiring additional estimated recoverable reserves. The Partnership may not be able to develop, exploit, find or acquire additional reserves to replace current and future production at acceptable costs. If the Partnership is unable to replace reserves as they are produced, the value of estimated reserves will decrease, and the business, financial condition and results of operations would be adversely affected.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel, and oilfield services could adversely affect the Partnership's ability to execute exploration and development plans within the established budget and on a timely basis. Shortages or the high cost of drilling rigs, equipment, supplies, personnel, or oilfield services could delay or adversely affect development and exploration operations or cause the Partnership to incur significant expenditures that are not provided for in its capital budget, which could have a material adverse effect on the business, financial condition, or results of operations.

Market conditions or operational impediments may hinder the Partnership's access to oil and natural gas markets or delay production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder the Partnership's access to oil and natural gas markets or delay production. The availability of a ready market for oil and natural gas production depends on several factors, including the demand for and supply of oil and natural gas and the proximity of estimated reserves to pipelines and terminal facilities. The Partnership's ability to market production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. The Partnership's failure to obtain such services on acceptable terms could materially harm the business. The Partnership may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If production becomes shut-in for any of these or other reasons, the Partnership would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

The Partnership may incur substantial losses and be subject to substantial liability claims because of oil and natural gas operations. Additionally, the Partnership may not be insured for, or current insurance may be inadequate to protect against, these risks. The Partnership is not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect the business, financial condition, or results of operations. The Partnership's oil and natural gas exploration and production activities are subject to all the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas, or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- personal injuries, fires, and death; and
- natural disasters.

Any of these risks could adversely affect the Partnership's ability to conduct operations or result in substantial losses because of:

- injury or loss of life;
- damage to and destruction of property, natural resources, and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of operations; and
- repair and remediation costs.

Further, the Partnership may elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on the Partnership's business, financial condition, and results of operations.

Wells that the Partnership decides to participate in may not yield oil or natural gas in commercially viable quantities. There is no way to predict in advance of drilling and testing whether any location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable the Partnership to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if enough oil or natural gas exist, the Partnership may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If the Partnership drills additional wells identified as dry holes in current and future drilling locations, the Partnership's drilling success rate may decline and materially harm its business. The Partnership cannot assure you that the analogies drawn from available data from other wells, more fully explored locations or producing fields will be applicable to drilling locations. In sum, the cost of drilling, completing, and operating any well is often uncertain, and new wells may not be productive.

The Partnership is subject to government regulation and liability, including complex environmental laws, which could require significant expenditures. The exploration, development, production and sale of oil and natural gas in the United States are subject to many federal, state, and local laws, rules, and regulations, including complex environmental laws and regulations. Matters subject to regulation include discharge permits, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation or environmental matters and health and safety criteria addressing worker protection. Under these laws and regulations, the Partnership may be required to make large expenditures that could materially adversely affect its financial condition, results of operations and cash flows. These expenditures could include payments for:

- personal injuries;
- property damage;
- containment and cleanup of oil and other spills;
- the management and disposal of hazardous materials;
- remediation and cleanup costs; and
- other environmental damages.

The Partnership does not believe that full insurance coverage for all potential damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of operations and subject the Partnership to administrative, civil, and criminal penalties, injunctive relief and/or the imposition of investigatory or other remedial obligations. Laws, rules, and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements. These laws, rules and regulations may impose liability on the Partnership for environmental damage and disposal of hazardous materials even without negligent or at fault. The Partnership may also be found to be liable for the conduct of others or for acts that complied with applicable laws, rules, or regulations at the time those acts were performed. These laws, rules and regulations are interpreted and enforced by numerous federal and state agencies. In addition, private parties, including the owners of properties upon which the Partnership's wells are drilled or the owners of properties adjacent to or near those properties may also pursue legal actions based on alleged non-compliance with certain of these laws, rules, and regulations.

Governmental regulation and liability for environmental matters may adversely affect the Partnership's business, financial condition, and results of operations. All the Partnership's intended acquisitions, operations and participations are onshore in the United States. Oil and natural gas operations are subject to various federal, state, and local government regulations that may change from time to time. Matters subject to regulation include:

- well locations;
- drilling and completion operations and methods;
- production amounts limited to below capacity;
- price controls;
- surface use and restoration;
- fluid and waste discharge from drilling operations;
- plugging and abandonment of wells (including the posting of bonds);
- well spacing;
- unitization and pooling of properties;
- taxation;
- marketing, transporting, and reporting production;
- valuation and payment of royalties';
- air emissions;
- groundwater uses and protection;
- the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes; and
- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

Federal, state, and local laws may require removal or remediation of previously disposed wastes, including wastes disposed of or released by the Partnership or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations at contaminated areas, or to perform remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at the site. CERCLA and analogous state laws also authorize the U.S. Environmental Protection Agency, or EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions. Other environmental laws provide for joint and several strict liabilities for remediation of releases of hazardous substances, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. In addition, the Partnership may be subject to claims alleging personal injury or property damage because of alleged exposure to hazardous substances such as oil and natural gas related products. As a result, the Partnership may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs.

Federal, state, and local laws and regulations relating primarily to the protection of human health and the environment apply to the development, production, handling, storage, transportation, and disposal of oil and natural gas, by-products thereof, and other substances and materials produced or used in connection with oil and natural gas operations. In addition, the Partnership may be liable for environmental damages caused by previous owners of property the Partnership purchase or lease. The Partnership is also subject to changing and extensive tax laws, the effects of which cannot be predicted. Compliance with existing, new, or modified laws and regulations could have a material adverse effect on the Partnership's business, financial condition, and results of operations.

Various state governments and regional organizations comprising state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as the Partnership's equipment and operations. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require the Partnership to incur additional operating costs and could adversely affect demand for the natural gas and oil sold. The potential increase in operating costs could include new or increased costs to obtain permits, operate and maintain current equipment and facilities, install new emission controls on all current equipment and facilities, acquire allowances to authorize greenhouse gas emissions, pay taxes related to greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

The Partnership may incur losses or costs because of title deficiencies in the properties in which the Partnership invests. If an examination of the title history of a property that the Partnership purchased reveals an oil and natural gas lease has been purchased in error from a person who is not the owner of the mineral interest desired, the Partnership's interest would be worthless. In such an instance, the amount paid for such oil and natural gas lease as well as any royalties paid pursuant to the terms of the lease prior to the discovery of the title defect would be lost.

Purchasers of production from oil and gas leases require "division orders" and "division order title opinions" from counsel before releasing funds to persons due payments from the purchase of oil and/or gas from a Partnership well. These documents tell the oil and gas purchaser who should be paid what. The division orders and accompanying title opinions can cost a substantial amount of money to prepare. Thus, paying to prepare a division order and title opinion before a well is tested will be a waste of money if the well proves to be dry. Consequently, the Managing General Partner anticipates that the Operator will wait until the well is tested to seek a final title opinion and division order. But the Managing General Partner anticipates that the Operator will obtain a preliminary title opinion before commencing operations and completed a preliminary title review of the spacing unit within which the proposed oil or gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, because of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such curative work entails expense. Failure to cure any title defects may adversely impact the Partnership's ability in the future to increase production and reserves. In the future, the Partnership may suffer a monetary loss from title defects or title failure. Additionally, unproved and unevaluated acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which the Partnership holds an interest, the Partnership will suffer a financial loss which could adversely affect the Partnership's financial condition, results of operations and cash flows.

Before well completion, the leasehold interests for Partnership oil and gas properties may be held by the Operator or its designee, as nominee, to facilitate operations and the acquisition of properties until the relevant well is tested. Unrecorded assignments will show that the nominee holds the leasehold interest for the benefit of the Partnership and this interest is not subject to the record owner's liabilities; however, such unrecorded assignments may not fully protect the Partnership from the claims by the Operator's creditors. Working Interest participants must rely on the Operator to use its best judgment to obtain appropriate title to the Partnership's leasehold interest. The Managing General Partner will take such steps as it deems necessary with the Operator to assure that title to its leasehold interests suits the Partnership's purposes. The Managing General Partner is free, however, to use its own judgment in waiving title requirements and will not be liable for any failure of title to leasehold interests transferred to or owned by the Partnership. Further, neither the Managing General Partner nor its Affiliates will make any warranties as the validity or merchantability of titles to any leasehold interests to be acquired by the Partnership.

Further, any title defect may result in a change of the Partnership's Working Interest or Net Revenue Interest relating to a Partnership Oil and Gas Property. If the Partnership is unable to recover the amounts paid to third parties for the pre-adjusted Working Interest or Net Revenue Partnership Unit, the amount paid for the adjusted portion may be deemed a loss by the Partnership.

Competition in the oil and natural gas industry is intense making it more difficult for the Partnership to acquire properties, market natural gas and secure trained personnel. The Partnership's ability to acquire additional prospects and to find and develop reserves in the future will depend on the ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many competitors possess and employ financial, technical and personnel resources substantially greater than the Partnership's. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than the Partnership's financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than the Partnership may be able to offer. The cost to attract and retain qualified personnel has increased in recent years due to competition and may increase substantially in the future. The Partnership may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on the Partnership's business.

The Partnership may not be able to keep pace with technological developments in the industry. The oil and natural gas industry are characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, the Partnership may be placed at a competitive disadvantage or competitive pressures may force the Partnership to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Partnership is able to do so. The Partnership may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies used now or in the future were to become obsolete or if the Partnership is unable to use the most advanced commercially available technology, the business, financial condition, and results of operations could be materially adversely affected.

Financial difficulties encountered by the Partnership's oil and natural gas purchasers, third party operators or other third parties could decrease cash flow from operations and adversely affect exploration and development activities. The Partnership derives essentially all its revenues from the sale of its oil and natural gas to unaffiliated third-party purchasers, independent marketing companies and mid-stream companies. Any delays in payments from such purchasers caused by financial problems encountered by them will have an immediate negative effect on the Partnership's results of operations and cash flows.

Liquidity and cash flow problems encountered by the Partnership's working interest co-owners or the third-party operators of the Partnership's non-operated properties may prevent or delay the drilling of a well or the development of a project. The Partnership's working interest co-owners may be unwilling or unable to pay its share of the costs of projects as they become due. In the case of a working interest owner, the Partnership could be required to pay the working interest owner's share of the project costs. The Partnership cannot assure you that they would be able to obtain the capital necessary to fund these contingencies.

The Partnership may not have enough insurance to cover all the risks faced and operators of prospects in which the Partnership participates may not maintain or may fail to obtain adequate insurance. In accordance with customary industry practices, the Partnership maintains insurance coverage against some, but not all, potential losses to protect against the risks faced. The Partnership does not carry business interruption insurance. The Partnership may elect not to carry insurance if management believes that the cost of available insurance is excessive relative to the risks presented. In addition, the Partnership cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on the Partnership's financial condition and results of operations. The impact of natural disasters or weather events in the areas where the Partnership operates has resulted in escalating insurance costs and less favorable coverage terms.

Oil and natural gas operations are subject to hazards incident to the drilling and production of oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires and pollution and other environmental risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operation. The Partnership does not operate the properties in which it holds an interest. In the projects in which it owns a non- operating interest directly, the operator for the prospect maintains insurance of various types to cover operations with policy limits and retention liability customary in the industry. The Partnership believes the coverage and types of insurance are adequate. The occurrence of a significant adverse event that is not fully covered by insurance could result in the loss of the Partnership's total investment in a particular prospect which could have a material adverse effect on financial condition and results of operations.

Terrorist attacks aimed at energy operations could adversely affect the Partnership's business. The continued threat of terrorism and the impact of military and other government action have led and may lead to further increased volatility in prices for oil and natural gas and could affect these commodity markets or the financial markets used by us. In addition, the U.S. government has issued warnings that energy assets may be a future target of terrorist organizations. These developments have subjected oil and natural gas operations to increased risks. Any future terrorist attack on the Partnership's facilities, customer facilities, the infrastructure depended upon for transportation of products, and, in some cases, those of other energy companies, could have a material adverse effect on the Partnership's business.

Producing oil and gas wells decline over time. Oil and gas wells flow due to pressure gradients. The oil and gas flows from the high-pressure areas to the collection point. Pumps and other production methods are used to maintain well pressure. As a well produces oil and/or gas from a reservoir, the reservoir pressure will decline with a corresponding effect on the amount of hydrocarbons collected. Investors should expect such declines. The actual decline curve is subject to numerous factors and cannot, in normal circumstances, be calculated in advance. The production from oil and gas wells is also subject to fluctuation for a myriad of reasons. Oil and/or gas production may not be stable on a month-to-month basis. At some point such production may decline to the point where the well is no longer commercially viable, and it will be shut in or plugged. No prediction can be made as to how long or at what rate such a decline may occur.

Initial Production Tests are not necessarily indicative of expected production. Some of the data presented may include initial production tests. Such tests are not meant to be predictors of eventual production but may factor into decision to complete a well. Such tests are conducted under ideal conditions using pressurized reservoirs and such reports are typically reported to the state oil and gas administrative agencies. Subscribers should expect that initial production test results will be higher than actual production rates, both immediately and over the long term.

Impact of the Dodd-Frank Act. In July 2010 Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act. This Act substantially changes financial regulation relating to the trading of commodities and commodity derivatives such as future contracts and thus may have a significant effect on the relevant prices for oil and gas going forward. For example, the Act requires that large banks spin off their proprietary trading operations, including their commodity trading operations. The Act may also impose limits on leverage used for trading commodities and commodity futures. Consequently, active traders in the oil and gas spot and futures market may possibly have less available capital to participate in these markets. The Dodd-Frank Act mandates hundreds of rule-making procedures and studies by financial regulatory agencies and the true impact of the Act will not be fully understood until those rules are issued and implemented, and those studies completed. The Managing General Partner makes no predictions or representations as to what impact the Dodd-Frank Act may have on the prices of oil and/or gas and related demand.

Proposed tax and energy industry legislation may materially impact the Partnership Wells' financial performance. Joe Biden was sworn in as President on January 20, 2021. Biden's campaign policies include:

- Requiring aggressive methane pollution limits for new and existing oil and gas operations.
- Using the Federal government procurement system – which spends $500 billion every year – to drive towards 100% clean energy and zero-emissions vehicles.
- Ensuring that all U.S. government installations, buildings, and facilities are more efficient and climate-ready, harnessing the purchasing power and supply chains to drive innovation.
- Reducing greenhouse gas emissions from transportation – the fastest growing source of U.S. climate pollution – by preserving and implementing the existing Clean Air Act and developing rigorous new fuel economy standards aimed at ensuring 100% of new sales for light- and medium-duty vehicles will be electrified and annual improvements for heavy duty vehicles.
- Doubling down on the liquid fuels of the future, which make agriculture a key part of the solution to climate change. Advanced biofuels are now closer than ever as we begin to build the first plants for biofuels, creating jobs and new solutions to reduce emissions in planes, ocean-going vessels, and more.

On January 27, 2021, President Biden issued an executive order that includes the following restrictions on oil and gas development in the United States:[1]

1) President Biden ordered the halt of new oil and gas leasing on federal onshore lands and offshore waters "to the extent consistent with applicable law." This pause will not affect existing operations or permits for existing leases, private lands or Native American tribal lands;
2) President Biden ordered the Secretary of the Interior to consider whether to adjust coal, oil, and gas royalties to account for corresponding climate costs, suggesting the possibility of a royalty increase; and
3) President Biden ordered the Department of the Interior to take steps toward conserving 30 percent of public lands and waters by 2030 and toward doubling offshore wind production in the same timeframe.

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[1] https://www.whitehouse.gov/briefing-room/presidential-actions/2222222/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/

President Biden had previously ordered halting the leasing program for the Arctic National Wildlife Refuge and effectively suspended new leases, contract or drilling permits on public lands for 60 days. Moreover, on January 20, 2021 – inauguration day – President Biden issued an executive order withdrawing the permit for the Keystone XL pipeline and ordered agencies to consider new rules to cut methane emissions from oil and gas. Finally, President Biden ordered federal agencies to work toward eliminating fossil fuel subsidies by fiscal 2022.[2]

In sum, the current Presidential Administration has taken policy positions adverse to the oil and gas exploration industry. The above-referenced policy changes and other future policy changes from the Biden Administration could have a material effect on the economic performance of the Partnership. These policies may diminish the anticipated demand for oil and gas and, correspondingly, the diminish the available prices for hydrocarbon products, which may result in not attaining anticipated revenue targets.

The Choice of Operator Carries Investment and Performance Risks. The Partnership well may be operated by an unaffiliated operator, especially initially. Drilling and completing oil and gas wells is a highly technical engineering endeavor that depends heavily on the skills and experience of the persons guiding the drilling and completion activities and working on the rig and the quality and implementation of the equipment and materials used to drill and complete the well. The specific day-to-day decisions and actions relating to drilling and completing a Partnership well will be made by the Operator and its contractors, not by the Managing General Partner and the Managing General Partner will have no substantive control or influence over these decisions and actions. Thus, the Partnership is relying almost entirely on the technical expertise of the operator to bring in the Partnership well. Further, the Partnership is also relying on the Operator to pay contractors for its portion of the well and to properly forward funds paid by the Partnership and other non-operating participants in the Partnership well. If the Operator fails to properly pay these contractors, they can file materialman and mechanics liens against the Partnership well and may stop working causing drilling or completion activities to cease. Consequently, the Partnership is also relying on the Operator's financial performance.

Bad weather may delay production and development activities. Adverse weather conditions may cause delays in drilling and completion operations. First, the delays could increase costs of operations as employees and equipment rentals may need to be paid while waiting on site. Partners are responsible for paying such increased costs through the completion of the well. Second, such delays could cause a delay in Partners receiving returns on investment, thus lowering the effective return on investment. Third, such delays could affect the tax year timing of deductibility of intangible drilling costs, especially if the Operator does not commence drilling operations on the Partnership Well by the deadline required under tax law. Fourth, such delays could affect oil and gas lease terms and delay rental payments. Finally, adverse weather could damage production and transport equipment used in collecting oil and gas from the Partnership well after the well is placed into production. The Partners may be liable for the cost of recovering from weather-related damage.

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2 https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/

The Partnership will have Uninsured Risks and Liabilities. The environmental, weather and title risks stated above are not likely to be substantially mitigated by insurance. Consequently, such risks could lead to the diminution of Partnership Unit values and cashflows. These risks could further lead to demands for additional capital from Partners should these liabilities exceed the value of the Partnership Units. Partners could be themselves liable for such liabilities.

The Partnership has risks relating to the financial conditions of the Operator's subcontractors. The Managing General Partner anticipates that the Operator will seek out solvent non-affiliated subcontractors, but, if a subcontractor does not timely pay for materials and services, those providers could file liens against Partnership well. In that event, the Partnership could incur excess costs in discharging these liens.

Shut-in Wells; Delays in Production and Seasonality. Production from wells drilled in areas remote from marketing facilities may be delayed until sufficient reserves are established to justify construction of necessary pipelines and production facilities. In addition, production from well may be reduced or delayed due to marketing demands which tend to be seasonal. The wells drilled for the Partnership may have access to only one potential market. Local conditions including but not limited to closing businesses, conservation, shifting population, pipeline maximum operating pressure constraints, and development of local oversupply or deliverability problems could halt sales from the Partnership well.

Delay in Distributions of Revenue. Distribution of revenue may be delayed for substantial periods of time after discovery of oil or gas due to unavailability of, or delay in obtaining, necessary material for completion of a well; payment of operating and/or development costs; reduced takes by purchasers of oil or gas due to market conditions; delays in obtaining satisfactory purchase contracts and connections for gas wells; delays in title opinions and obtaining division orders; and other circumstances.

Asset Concentration. The Partnership wells are currently intended to be in the Permian Basin of Texas and New Mexico. Consequently, investors should understand that there will be little diversity for these assets. Further, there are intended to be only a small number of Partnership producing wells, thus concentrating operational risks. Any operational problems with any well could have a material impact on Partnership performance. Finally, all the Partnership's assets will consist of participations in oil and gas drilling ventures. So, the Partnership's assets will be completely focused on one type of activity (exploration and production) in one industry (domestic oil and gas production) in only one area (Permian Basin of Texas and New Mexico). The Partnership will not have a diversified portfolio.

Owning Working Interest positions in the Partnership Wells. The Managing General Partner might not receive optimal pricing if it seeks to sell the Partnerships' Working Interest in the Partnership Wells. There may be a valuation discount per Working Interest percentage if the Partnership sells its interest in a Partnership Well versus tagging along with the Operator's sale of the entire well or leasehold. Subscribers should anticipate holding their Partnership Units for an extended period of time as the Partnership may be required to hold one or more of its Partnership Well Working Interests for an extended period of time, especially during a period with adverse pricing pressure on oil and gas Working Interests in the Permian Basin.

Tax Risks

Oil and gas exploration in the United States benefits from several favorable U.S. tax rules, including depletion allowances and the option to expense intangible drilling and completion costs. Further, a partnership may also bring tax benefits under U.S. law. But, U.S. lawmakers, the U.S. Internal Revenue Service, and U.S. courts could modify or eliminate these favorable treatments. Further, the limited tax benefits associated with oil and gas exploration do not eliminate oil and gas production risks. See "Tax Aspects."

Tax Shelter Registration. The Managing General Partner will not apply to the U.S. Internal Revenue Service to register the Partnership as a "tax shelter." If the Partnership is subsequently determined to be a tax shelter requiring registration by the IRS, Partners could incur substantial penalties for this non-registration. The Managing General Partner does not believe that an investment in the Partnership will generate tax losses that exceed the amount invested and does not believe that the Partnership is a tax shelter but provides no assurance that the IRS will agree with that evaluation.

Tax Abuse Reclassifications. The IRS can seek to reclassify or disregard partnership transactions that it believes were used to avoid tax, particularly if a transaction has no independent economic substance. The Managing General Partner believes that its transactions will have independent economic substance and will not be abusive but can provide no assurance that the IRS will agree with that evaluation.

Tax Liabilities in Excess of Cash Distributions. Partnerships taxed as partnerships are pass-through tax entities under U.S. law. This means that the Partnership's losses and gains are taxed to the Partners on a pro-rata basis, and Partners can have taxable income, even if they have not received the corresponding cash. The Managing General Partner anticipates distributing revenue on a timely basis, but an unanticipated delay may cause the partners to realize income without receiving the corresponding cash. The decision to make a distribution will be in the sole discretion of the Managing General Partner. Further, the Limited Partnership Agreement does not allow the Partnership to incur debt. But, if the Partnership for some reason accrues debt, paying debt derived from income may cause the partners to realize income without receiving the corresponding cash.

Chance of Audits. The Partnership may be subject to tax audits which may lead to taxable income adjustments for the Partners. The Managing General Partner provides no assurance that the Partnership's tax deductions will survive a challenge from the IRS.

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

Treatment of Partner's Losses and Income as Passive. If a Subscriber invests as a limited partner, the Limited Partner's Partnership losses and income will be treated as passive. If a Subscriber invests as an Additional General Partner, but has previously participated in exploration and production activities involving a well that produces from the same reservoir as the reservoir to be used targeted or used for the Partnership Wells and that Additional General Partner made that previous participation using a business entity which would have provided limited liability to the Additional General Partner for that Venture, then the Additional General

Partner's income and losses from the Partnership Wells will be treated as passive income and losses, subject to passive loss limitations.

Material Portion of Subscription Proceeds Not Currently Deductible. A material portion of the Subscription proceeds may be expended for items which will not be currently deductible for Federal income tax purposes. These include the proceeds used to pay distribution expenses and offering and organizational expenses. The distribution and offering expenses will likely be deemed to be selling expenses and are not amortizable. Costs classified as "organizational costs" may be amortized over 15 years, and thus will provide little or no near-term tax benefit. Reasonable project management fees may be deducted as ordinary and necessary business expenses as the work is performed.

Treatment of Intangible Drilling and Completion Costs. The Managing General Partner will provide an allocation of intangible drilling and completion costs to Partners. If the IRS later determines that some of those costs should have been classified as selling, title, legal or other expenses that are not currently deductible (or not deductible at all), it will seek to disallow deductions based on that portion of the intangible drilling and completion costs and seek payment of corresponding taxes and penalties. The allocation of intangible drilling and completion costs is a frequent subject of IRS review, and the Managing General Partner makes no prediction as to what such a review may find.

Depletion. Depletion is calculated at Partner level by each Partner. Different Partners can have different depletion allowances. The Managing General Partner anticipates that most Partners will have their depletion determined on the greater of cost or percentage depletion basis. This means that the depletion is based on the amount of production in any year versus the estimated reserves as determined under the Tax Code. However, some Partners may qualify as "independent producers" and be able to use percentage depletion. Percentage depletion allows a deduction equaling up to 15% of the taxpayer's gross income from the property per taxable year, provided, in general, that the percentage depletion deduction 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 (computed without regard to percentage depletion and net operating loss and capital loss carrybacks). If a Partner seeks to use percentage completion and is subsequently deemed not to be an "independent producer," it would have adverse tax consequences. Further, the Managing General Partner anticipates that the Partnership Well will not qualify as a type of well that will generate accelerated depletion allowances. The Managing General Partner urges Partners to consult their own tax adviser in determining depletion allowances.

Partnership Status. Partnerships are generally taxed as pass-through tax entities. The Partnership intends to seek to be taxed as a partnership. Certain partnerships, particularly publicly traded partnerships, may be taxed as corporations. The Managing General Partner has no intent to seek a trading market for the Units and does not believe that the Partnership will be treated as a publicly traded partnership. Further, the Managing General Partner makes no prediction as to whether any future changes in the law of partnerships would affect the tax or partnership status of the Partnership. The Partnership will be subject to ongoing changes in applicable law.

Unrelated Business Taxable Income ("UBTI"). UBTI is income on which a tax-exempt entity is required to pay tax. UBTI income is derived from a trade or business regularly carried by the tax-exempt organization that is not substantially related to the exempt organization's exempt function. (e.g., the operation of an equipment rental business by a hospital). Investment-type income generally is not UBTI unless it is financed with debt. The Partnership Agreement does not permit the Partnership to incur debt.

Significance of Tax Aspects. The Partnership Units may have U.S. tax benefits, but there is no assurance that money invested in the Partnership will be recovered or that the Partnership's present interpretations of U.S. tax laws will not be changed or challenged. The Managing General Partner suggests that prospective investors obtain professional guidance from their tax advisor in evaluating the tax risks involved in investing in a Partnership and prefers that the investment decision should be motivated by a desire to have a return on investment rather than accruing related tax benefits.

Specific Risks of this Offering

Key Personnel Risk. The Partnership depends on key personnel of the Managing General Partner, including S. Jeffrey Johnson and Jake Johnson, for the management development of the Partnership's business. The success of the Partnership's business depends on the key personnel's commitment to the enterprise and their personal relationships with operators, landmen and contractors. If any of the key personnel become unavailable to the Partnership for any reason, the Partnership's business could be severely impacted.

Reliance on Managing General Partner. The Managing General Partner's solvency and financial resources will materially affect the Managing General Partner's ability to fulfill its obligations to the Partnership. Further, the Managing General Partner will have seventy-five (75%) of the Partnership's voting interest. This means that the Limited Partners and Additional General Partners will not have a vote that could affect the Partnership's decisions unless the Managing General Partner chooses to abstain from voting. If the management of the Managing General Partner becomes unable or unwilling to continue to direct the operations of the Partnership, the Partnership and the Partners could be adversely affected.

Negligence of Operator. The Operator is required to maintain general liability insurance. But there can be no assurance that the dollar amount of insurance coverage will be sufficient to pay such claims**.** Consequently, claims may be made against the working interest, including the Partnership's working interest. Such claims may negatively affect Partners' capital accounts and distributions.

Substitute Well Location. The Managing General Partner reserves the right to move a Partnership Well's location or a Partnership Prospect from that described in this Memorandum in the event (in the sole judgment of the Managing General Partner) additional geological information warrants the move. Additionally, the Managing General Partner reserves the right to substitute for, or add to, the specified oil and gas prospects if (in the sole judgment of the Managing General Partner) the development of a specific prospect becomes imprudent or inadvisable. In such event, Partners may not have an opportunity before purchasing Units to evaluate for themselves the relevant geophysical, geological, economic, or other information regarding the prospect(s) to be selected. If a new prospect or prospects are selected, delays in the investment or proceeds from this offering may occur.

Assessments. If after a well has been completed and placed into production, the Operator determines that additional rework on the well is necessary; the Partnership could receive an additional assessment relating to that rework.

Other Working Interest Owners. The Partnership Wells will have other working interest owners besides the Partnership. If any such other Working Interest owners are unable to furnish the funds required to pay for drilling, testing and/or completion associated with its Working Interests in the well, their portion may be paid by another Working Interest owner and such defaulting Working Interest owner may be penalized.

Limited Experience and Capital. The Partnership was only recently organized and has no history of operation and very limited capital.

Arbitrary Offering Price. The offering price and terms for the Units were arbitrarily fixed by the Managing General Partner based upon the Partnership's presently contemplated financing needs. No investment banker or other appraiser was consulted regarding such price and terms. The offering price bears no relationship to the potential value of the Partnership Wells or the possible future earnings of the Partnership.

Winding-Up of the Partnership. The Partnership may be terminated upon the occurrence of certain events as stated in the Partnership Agreement, 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. Upon liquidation, Partnership obligations will be paid. 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. The Managing General Partner has the right to terminate the Partnership as provided in the Partnership Agreement.

Reliance on Projections and/or Opinions**.** No agents of the Managing General Partner have been authorized to make any projections or express any opinion concerning future events, expected production, or availability of tax benefits, except as set forth within this Memorandum. No oral opinions which differ from the written data provided prospective investors have been authorized and should not be relied upon. Opinions of possible future events are based upon various subjective determinations and assumptions. All projections by their very nature are inherently subject to uncertainty; accordingly, a prospective investor will be subject to the risk that any such projections will not be reached, that any such underlying assumptions may prove to be inaccurate.

Liability and Indemnification of the Managing General Partner. The Partnership Agreement provides that the Managing General Partner will not be liable to the Partnership or to any Partner for and will be indemnified and held harmless by the Partnership in respect of, the consequences of any act or failure to act of the Managing General Partner unless such act or omission constitutes gross negligence or willful misconduct. The existence of these provisions grants to the Partners more limited causes of action than they might otherwise have had against the Managing General Partner in the absence of such provisions.

Arbitration. Disputes with the Managing General Partner arising from the purchase of Units in the Partnership by a Partner are subject to arbitration sponsored by the American Arbitration Association, rather than civil litigation filed in court. Such dispute resolution may be viewed as depriving the Partners of their full legal remedies.

Absence of Registration under Applicable Securities Laws. Prospective investors must recognize that the Units have not been, nor will they be, registered with the SEC or any State or Provincial Securities Administrator. Subsequently, no sale can be made without registration, unless there is an applicable registration exemption. No regulatory authority has reviewed the nature and amounts of compensation to be paid to the Managing General Partner, the disclosure of risks and tax consequences inherent in such investment, or the other terms of this offering. Prospective investors must recognize that they do not necessarily have all the protections afforded by federal, state, or provincial securities laws to registered or qualified offerings. They must therefore judge for themselves the adequacy of the disclosures, the amounts of such compensation, and the fairness of the other terms of this offering without the benefit of prior review by any regulatory authority.

Limits on Transferability of the Units. Partners are unlikely to be able transfer units. The Managing General Partner must consent to any subsequent sale if the transferee is to become a Substitute Partner. In that regard, the Managing General Partner may also require an opinion of counsel to the effect that any such transfer will not violate applicable federal, state, or provincial securities laws. The Units will not be, and the purchasers of the Units have no right to require that they be, registered under the Act. There will be no public market for the Units and no market is expected to develop. In addition, each transferee of any Units must, unless specifically exempted by the Managing General Partner, satisfy the suitability standards contained herein. No assurances can be given that transferees meeting these standards will be interested in acquiring any Units in the Partnership. Neither the Partnership nor the Managing General Partner has an obligation to repurchase any of the Units from the Partners. The Units may become progressively less attractive to any prospective purchaser thereof because the anticipated tax benefits associated with an investment in the Partnership will decline over time as the Partnership Wells are drilled, tested, and completed and because of the payment of nonrecurring fees to be deducted by the Partnership in the earlier years of the Partnership.

No Market for Partnership Units. There is no market for the resale of the Partnership Units and the Managing General Partner anticipates that no such market will ever develop. This means that there is no liquidity or pricing mechanisms for the resale of Partnership Units. Indeed, to maintain its status as a pass-through tax entity, the Partnership should avoid arranging for a liquid market for its Units. Consequently, Partners will have difficulty reselling the Units and such resales may not be completed at competitive prices. Investors should understand that the Partnership Units will likely be held as long-term investments.

No Redemption Rights. The Managing General Partner has no obligations to repurchase any Partnership Units.

TERMS OF THE OFFERING

The Partnership. The Managing General Partner, on behalf of the Partnership, hereby offers 50 Units of PB Non-op Drilling LP Partnership Units priced at $100,000 per Unit for a Subscription Amount of $5,000,000, which may be increased to a maximum Subscription Amount of up to $10,000,000 (100 Units) at the Managing General Partners sole discretion.

***Deposit and Use of Funds*.** The Subscription payments received by the Partnership will initially be paid to the Partnership, which shall pay the designated portion to the Managing General Partner.

Revenues from operations of the Partnership will be collected by the Managing General Partner and deposited in a Partnership production bank account from which the Managing General Partner will pay all Operating Costs and General and Administrative Costs incurred by the Partnership.

Subscription Procedure and Payment. Initial payments for Subscriptions for the Units described herein will be payable upon the execution of the Subscription Documents. The Managing General Partner will require the submission of Subscriptions accompanied by cash or check made payable to PB Non-op Drilling LP in the initial deposit amount of $100,000 per Unit subscribed. Subscriptions must be for whole Units with a one unit minimum unless the Managing General Partner waives the minimum.

PLAN OF DISTRIBUTION AND RETROCESSION PAYMENTS

The Partnership Units will be sold by the Managing General Partner. The Managing General Partner may use finders registered with the Texas State Securities Board pursuant to Texas State Securities Board Rule 115.11. Any finder compensation shall be paid from the Managing General Partner's Partnership Units and shall not dilute Subscribers' interest in the Partnership.

The Managing General Partner may provide a portion of its management fee to offset clients' advisory fees relating to an allocation to the Partnership Units for the first year of such fees. In addition to such investment adviser client fee reimbursement, the Managing General Partner will also be paying registered investment advisers, may receive the following: 1) the Managing General Partner will pay up to 3.0% of its first year advisory fees relating to advised Subscribers to the Subscriber's investment adviser; and 2) the Managing General Partner, in its sole discretion, may assign Subscriber's investment adviser or its affiliate an interest in the Partnership that will be subordinated to the Subscribers' Partnership Units. These arrangements with Subscribers' investment advisers shall be paid from the Managing General Partner's Partnership Interest and shall not dilute Subscribers' interest in the Partnership.

FORWARD LOOKING STATEMENTS AND ASSOCIATED RISKS

Statements, other than statements of historical facts, included in this Memorandum and its exhibits address activities, events or developments that the Managing General Partner and the Partnership anticipate will or may occur in the future. These forward-looking statements include such things as estimated oil and gas reserves, estimated recoverability of oil and gas reserves, oil and gas prices, well drilling and completion costs and budgets, environmental conditions, weather, quality and timely delivery of equipment and materials to the wellsites, regulatory compliance, tax treatments, competition, management expertise and other similar matters. These statements are based on certain assumptions and analyses made by the Partnership and the Managing General Partner considering their experience and their perception of historical trends, current conditions and expected future developments. However, whether actual results will conform with these expectations is subject to several risks and uncertainties, many of which are beyond the control of the Partnership, including general economic, market or business conditions, changes in laws or regulations, the risk that the wells are productive but does not produce enough revenue to return the investment made, the risk that the wells are dry holes, uncertainties concerning the price of gas and oil, and other risks. Thus, all the forward-looking statements made in this Memorandum and its exhibits are qualified by these cautionary statements. There can be no assurance that actual results will conform to the Managing General Partner's and the Partnership's expectations.

PROPOSED ACTIVITIES

Oil and gas exploration involves a high degree of risk because of the many uncertainties inherent in locating and developing oil and gas reservoirs. Neither scientific techniques nor management expertise can eliminate those risks. Notwithstanding the presence of such uncertainty, the Partnership plans to participate in the Partnership Wells.

Investment Objective

The primary investment objective of the Partnership is to participate in the drilling and production of oil and gas in commercial quantities.

Plan of Operations

PB Non-op Drilling LP plans to participate in oil and gas wells in the Permian Basin (the "Partnership Wells"). The Partnership will bid on the Partnership Wells non-operating Working Interest. The Managing General Partner will not operate the wells. The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest. 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. The Partnership Wells will be sourced from Whitefish Management, LLC. Jake Johnson, a beneficial owner of Crimson Creek

Holdings, LLC, an owner of the Managing General Partner, is a member of Whitefish Management, LLC.

Description of Operator

The Operator designation will depend on the Partnership winning the bid for the non-operating Working Interest.

Cost of Operations

The Partnership will participate in the Operator's well(s) by paying its share of the expenses pursuant to an Authorization for Expenditures (AFE). The AFE is an estimated budget and costs may exceed the AFE, in which case the Partnership will be billed for such amounts. The Managing General Partner will contribute services it believes have an approximate value equal to a ten percent (10%) cost plus fee on the actual well or leasehold costs, including the costs of property acquisition, drilling and completion paid to the Operator. The fee is contingent on the amount raised.

Market

As of December 5, 2023, the natural gas (Henry Hub - Louisiana) spot price was $2.72 per MMBTU on NYMEX according to the U.S. Energy Information Administration. As of December 6, 2023, the spot price for West Texas Intermediate Crude (Cushing, Oklahoma) was $68.98 per BBL and the spot price for Louisiana Light Sweet Crude was $71.98 per BBL according to the U.S. Energy Information Administration. The net prices obtained for gas and oil will likely differ from the referenced market quotes due to transportation costs and the way such transportation costs are assigned in the oil and gas leases and differences in the designated quality of the oil or gas. For example, in some leases, transportation costs can be charged against the royalty interests and in others such costs cannot be charged against those interests. In general investors should expect that the realized price will be less than the prices posted on the commodities exchanges for specifically designated locations because there is no commodities exchange-based trading market for prices of oil and gas at the Partnership Well wellheads. The price obtained will be the price negotiated with the local purchaser.

Substitute Well Location or Decision Not to Drill

The Managing General Partner 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 General Partner 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 Memorandum.

MANAGEMENT

The Partnership Wells will be identified by Whitefish Management, LLC and the Managing General Partner. Jake Johnson, a beneficial owner of Crimson Creek Holdings, LLC, an owner of the Managing General Partner, is a member of Whitefish Management, LLC. The decision to participate in the Partnership Wells will be made by the Managing General Partner. Our Managing General Partner, PB Non-op Drilling GP, LLC, is indirectly managed and beneficially owned by S. Jeffrey Johnson and Jake Johnson.

S. Jeffrey Johnson

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.

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.

Richard Loomis

Richard Loomis, Vice President of Marketing, PR and Investor Relations, 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 oversees 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.

Mr. Loomis develops 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 LNG company build infrastructure to handle the marine fuels industry and has consulted on major pipeline infrastructure projects.

TAX ASPECTS

THE TAX PORTIONS OF THIS MEMORANDUM ARE NOT, AND SHOULD NOT BE CONSTRUED TO BE, TAX ADVICE TO ANY PERSON OR ENTITY INVESTING IN OR CONSIDERING INVESTING IN THIS OFFERING. EACH INVESTOR AND POTENTIAL INVESTOR SHOULD RELY EXCLUSIVELY ON SUCH INVESTOR'S TAX AND FINANCIAL PROFESSIONAL ADVISORS FOR THE RENDITION OF TAX ADVICE IN CONNECTION WITH THIS OFFERING.

CIRCULAR 230 DISCLOSURE: PURSUANT TO U.S. TREASURY DEPARTMENT REGULATIONS, YOU ARE ADVISED THAT UNLESS OTHERWISE EXPRESSLY INDICATED, ANY FEDERAL TAX ADVICE CONTAINED IN THIS COMMUNICATION, INCLUDING ATTACHMENTS AND ENCLOSURES, IS NOT INTENDED OR WRITTEN TO BE USED, AND MAY NOT BE USED FOR THE PURPOSE OF (1) AVOIDING TAX-RELATED PENALTIES UNDER THE INTERNAL REVENUE CODE, OR (2) PROMOTING, MARKETING, OR RECOMMENDING TO ANOTHER PARTY ANY TAX-RELATED MATTERS ADDRESSED HEREIN.

A limited partnership taxed as a partnership incurs no federal income tax liability under US law. Instead, taxable income and losses are passed through to its member, although the limited liability company must file information returns with the IRS. In general, the character of a Partner's share of each item of income, gain, loss, deduction, and credit is determined at the Partner level. The Partnership will allocate each Partner a share of these items as required by the Partnership Agreement to determine the Partner's income or loss. Partners report these profits and losses without regard to whether the Partner has received or will receive any cash distributions from the Partnership. So, Partners could be liable for income taxes on profits without receiving any corresponding cash payments.

The Tax Cut and Jobs Act

On December 22, 2017, President Trump signed The Tax Cut and Jobs Act, into law. The following is not tax advice. Seek the advice of your own tax advisor.

Bonus Depreciation

New Section 168(k)(2) allows bonus depreciation for any qualified property with a depreciable life of 20 years or shorter. The qualified property with depreciable life of 20 years or shorter may include oil and gas equipment such as tanks, pumps, and pipeline (provided the asset is qualified and has a depreciable life of 20 years or less). Such assets may be subject to a temporary bonus depreciation which would result in a pass-through write-off of up to one hundred percent (100%) of the potential depreciation of such qualified equipment. This results from The Tax Cuts and Jobs Act of 2017 which temporarily enhances bonus depreciation. Under the Act, for qualified assets (i) with a depreciation schedule of twenty (20) years or less and (ii) placed in service between September 28, 2017, and December 31, 2022 (or by December 31, 2023, for certain property with longer production periods), the first-year bonus depreciation deduction increases to one hundred percent (100%) for both new and used assets placed into service. Beginning in 2023, bonus depreciation is scheduled to be reduced twenty (20) percentage points each year, until it is fully eliminated in 2027.

Alternative Minimum Tax

A material provision of The Tax Cut and Jobs Act addresses the Alternative Minimum Tax ("AMT"). For 2017 the AMT is imposed on an individual, estate, or trust in an amount by which the tentative minimum tax exceeds the regular income tax for the taxable year. For taxable years beginning in 2017, the tentative minimum tax is the sum of (1) 26 percent of so much of the taxable excess as does not exceed $187,800 ($93,900 in the case of a married individual filing a separate return) and (2) 28 percent of the remaining taxable excess. For 2017, the exemption amounts are phased out by an amount equal to 25 percent of the amount by which the individual's AMTI exceeds (1) $160,900 in the case of married individuals filing a joint return and surviving spouses, (2) $120,700 in the case of other unmarried individuals, and (3) $80,450 in the case of married individuals filing separate returns or an estate or a trust. The AMT is also subject to numerous preferences and adjustments for certain types of income and deductions.

The AMT thresholds and AMT phase-out thresholds will be temporarily increased for the 2018 – 2025 tax tears, as shown by the following table.

The Tax Cut and Jobs Act AMT Impact

Description	2017 Single Filer	2018-2025 Single Filer	2017 Joint Filers	2018-2025 Joint Filers
AMT Exemption Threshold	$54,300	$70,300	$84,500	$109,400
AMT Exemption Phaseout Threshold	$120,700	$500,000	$160,900	$1,000,000

Taxation of Pass-Through Entities

The Tax Cut and Jobs Act adds Internal Code Revenue Section 1099A which materially decreases the tax rates on business entities taxed as partnerships. For 2018 through 2025 ordinary income tax rates for oil and gas Partnerships taxed as partnerships will include a 20% deduction from taxable income generated by the Partnership. The deduction needs to be taken by the taxpayer, not the Partnership.

But this deduction is limited by payment of W-2 income to employees and income thresholds. The deduction generally would be limited to the greater of 50% of the taxpayer's pro rata share of domestic wages paid by the business; or the sum of 25% of such wages and 2.5% of the initial basis of tangible depreciable property used in the business. The limitation is phased in for individuals with taxable income exceeding $315,000 in the case of a joint return (or $157,500 for single filers).

These wage restrictions and income thresholds means that Section 1099A will likely not be a benefit to Subscribers to Partnership Units.

TAX SHELTER RULES

The Tax Code provides that promoters must register certain investments must as tax shelters with the IRS. These tax shelter promoters must provide registration numbers to investors who are required to report the numbers on their personal tax returns. They must also prepare and maintain lists of the tax shelters' participants. The Tax Code and Treasury Regulations define "tax shelters" in several different ways and impose different obligations on the tax shelter's promoters and participants depending on the type of tax shelter. Some types of tax shelters must be "registered" with the IRS, while others, called "Reportable Transactions," must be disclosed to the IRS. The Managing General Partner believes that the Partnership will not be considered a tax shelter under any of the various definitions in the Tax Code and Treasury Regulations.

The registration requirements apply to an investment with respect to which any person could reasonably infer from the representations made, or to be made, in connection with the offering for sale of interests in the investment that the "tax shelter ratio" for any investor is greater than two to one as of the close of any of the first five years ending after the date on which such investment is offered for sale. Temp. Treas. Reg. § 301.6111-1T.

The Managing General Partner believes that: (i) based on it and its Affiliates' experience with previous drilling programs and on the Partnership's planned operations, the Partnership will not have a tax shelter ratio greater than two to one, (ii) the investor's potentially allowable deductions and credits will not result in any Partnership having a tax shelter ratio greater than two to one, and (iii) based upon a review of the economics of similar oil and gas drilling programs for the past several years, it has determined that none of those programs has resulted in a tax shelter ratio greater than two to one. Accordingly, the Managing General Partner does not intend to cause the Partnership to register with the IRS as a tax shelter.

If the IRS or the Managing General Partner subsequently determine that the Partnership should have been registered as a tax shelter with the IRS, the Partnership would be subject to certain penalties under Tax Code § 6707, including a penalty ranging from $500 to 1% of the aggregate amount invested in the Partnership Units for failing to register and $100 for each failure to furnish to a Partner a tax shelter registration number, and each Partner would be liable for a $250 penalty for failure to include the tax registration number on his tax return, unless such failure was due to reasonable cause. A Partner also would be liable for a penalty of $100 for failing to furnish the tax shelter registration number to any transferee of his Partnership Units. The Managing General Partner can give no assurance that, if the Partnership is determined to be a tax shelter that must be registered with the IRS, the above penalties will not apply.

In addition to the tax shelter registration requirements described above, (i) every taxpayer that participates in a "Reportable Transaction" generally must disclose the transaction to the IRS using Form 8886 and (ii) every organizer and seller of a "Potentially Abusive Tax Shelter" (that is generally a reportable transaction or a tax shelter that is required to be registered) generally must prepare and maintain a list of each of the participants in the transaction. See Treas. Reg. §§ 1.6011-4 and 301.6112-1. A Reportable Transaction (and accordingly, by definition, a Potentially Abusive Tax Shelter) includes certain transactions that give rise to a significant book- tax difference. Treas. Reg. §§ 1.6011-4(b)(6) and 301.6112-1(b)(2)(i)(B). But a book-tax difference caused by expensing intangible drilling costs pursuant to Tax Code § 263(c) is not considered for these purposes. Rev. Proc. 2003-25, § 4.04, 2003-11 I.R.B. 601 (February 27, 2003). In addition, the Partnership does not otherwise satisfy the definition of a Reportable Transaction. Therefore, the Managing General Partners believes that an investment in the Partnership will not be a Reportable Transaction. Furthermore, the Managing General Partner believes that the Partnership will not be a Potentially Abusive Tax Shelter because an investment in the Partnership will not be a Reportable Transaction and because the Partnership will not be a tax shelter that is required to be registered. Consequently, the Managing General Partner anticipates that the Partners will not be required to disclose the Partnership as a tax shelter on Form 8886 and the Managing General Partner will not be required to maintain a list of the Partners as participants in a tax shelter.

DEPRECIATION DEDUCTIONS

The Partnership will claim depreciation, cost recovery, and amortization deductions with respect to its basis in Partnership Property as permitted by the Tax Code. For most tangible personal property placed in service after December 31, 1986, the "modified accelerated cost recovery system" ("MACRS") must be used in calculating the cost recovery deductions. Thus, the cost of lease equipment and well equipment, such as casing, tubing, tanks, and pumping units, and the cost of oil or gas pipelines cannot be deducted currently but must be capitalized and recovered under "MACRS." The cost recovery deduction for most equipment used in domestic oil and gas exploration and production and for most of the tangible personal property used in natural gas gathering systems is calculated using the 200% declining balance method switching to the straight-line method, a seven-year recovery period, and a half-year convention.

General Partner will not be required to maintain a list of the Partners as participants in a tax shelter.

PARTNERSHIP AUDIT SIMPLIFICATION ACT OF 2015

In November 2015, President Obama signed the Partnership Audit Simplification Act of 2015 after its passage by Congress. It provides that any adjustment of income, gain, loss, deduction, credit, tax, penalty, or addition to tax for a limited partnership taxed as a partnership (and any Partner's distributable share of the Partnership) shall be determined at the Partnership level. Partners will not be able to file, challenge or negotiate separately with the Internal Revenue Service. Partners will be bound by the actions of the Partnership as undertaken by and through the Managing General Partner, acting as the "Partnership Representative" under Tax Code § 6223.

Further, the Partnership will be liable under the Partnership Audit Simplification Act of 2015 for any subsequent adjustments, penalties, and additional taxes at the date of such imposition, regardless of whether the partnership ownership or ownership percentages of changed since the previous tax treatment. So, there is a risk that new Partners in subsequent years could be indirectly subject to economic liability through the Partnership for tax treatments for which they previously received no benefit. As stated elsewhere, the Partner Units will have no market and carry substantial restrictions on transferability. Consequently, the Managing General Partner does believe that such subsequent year transfers of Partnership Units will be a common occurrence.

The Partnership Audit Simplification Act of 2015 provides that limited liability companies taxed as partnerships with fewer than 100 partners who have no other business entities taxed as partnerships (such as limited partnerships or limited liability companies) as partners may opt out of the Code provisions providing for taxes at the Partnership level. The Partnership Agreement does not contain any such opt out language. The Managing General Partner reasonably expects that some Subscribers will subscribe to the offering using a limited liability company or a partnership, thus making the opt-out provisions unavailable to the Partnership.

New Tax Code § 6235 under the Partnership Audit Simplification Act of 2015 creates a single statute of limitations for Partners, providing that an adjustment under the Act's new rules cannot be made three years after the later of: (i) the date the limited liability company filed its return; (ii) the limited liability company return's due date; or (iii) the date on which the limited liability company filed an administrative adjustment request. This period may be extended pursuant to an agreement between the IRS and the limited liability company.

Similarly, the Partnership Audit Simplification Act of 2015 significantly alters the period for a limited liability company to file an administrative adjustment request. First, new Tax Code § 6227 provides that an administrative adjustment request may not be filed after the IRS issues a notice of administrative proceeding to the limited liability company. Second, and perhaps most importantly, unlike previous law, the extension of a limited liability company's assessment statute of limitations does not simultaneously extend the period to file an administrative adjustment request. Taken together, these two revisions significantly curtail a limited liability company's ability to file administrative adjustment requests.

INTEREST DEDUCTIONS

In the Transaction, the Partners will acquire their interests by remitting cash in the amount of up to $100,000 per Unit to the Partnership. The Partnership will not accept notes in exchange for a Partnership Units. Nevertheless, without any assistance of the Managing General Partner or any of its Affiliates, some Partners may choose to borrow the funds necessary to acquire the Partnership Units and may incur interest expense in connection with those loans. The Managing General Partner makes no representations on the tax treatment of the interest on such loans.

TRANSACTION FEES

The Partnership may classify a portion of the fees (the “Fees”) to be paid to third parties and to the Managing General Partner or to the Operator and its Affiliates (as described in the Offering Memorandum under “Source of Funds and Use of Proceeds”) as expenses that are deductible as organizational expenses or otherwise. The Managing General Partner makes no assurance that the IRS will allow the deductibility of such expenses.

Generally, expenditures made in connection with the creation of, and with sales of interests in, a partnership will fit within one of several categories.

A limited liability company taxed as a partnership may elect to amortize and deduct its organizational expenses (as defined in Tax Code § 709(b)(2) and in Treas. Reg. § 1.709-2(a)) ratably over a period of not less than 180 months commencing with the month the partnership begins business. Organizational expenses are expenses that (i) are incident to the creation of the partnership, (ii) are chargeable to capital account, and (iii) are of a character that, if expended incident to the creation of a partnership having an ascertainable life, would (but for Tax Code § 709(a)) be amortized over such life. Id. Examples of organizational expenses are legal fees for services incident to the organization of the partnership, such as negotiation and preparation of a limited liability company agreement, accounting fees for services incident to the organization of the partnership and filing fees. Treas. Reg. § 1.709-2(a).

Under Tax Code § 195, no deduction is allowable with respect to “start-up expenditures,” although such expenditures may be capitalized and amortized over a period of not less than 180 months. Start-up expenditures are defined as amounts (i) paid or incurred in connection with (I) investigating the creation or acquisition of an active trade or business, (II) creating an active trade or business, or (III) any activity engaged in for profit and for the production of income before the day on which the active trade or business begins, in anticipation of such activity becoming an active trade or business, and (ii) that, if paid or incurred in connection with the operation of an existing active trade or business (in the same field as the trade or business referred to in (i) above), would be allowable as a deduction for the taxable year in which paid or incurred. Tax Code § 195(c)(1).

The Partnership intends to make payments to the Managing General Partner, as described in greater detail in this Memorandum. To be deductible, compensation paid to a general partner must be for services rendered by the partner other than in his capacity as a partner or for compensation determined without regard to Partnership income. Fees which are not deductible because they fail to meet this test may be treated as special allocations of income to the recipient partner (see Pratt v. Commissioner, 550 F.2d 1023 (5th Cir. 1977)), and thereby decrease the net loss or increase the net income among all partners.

To the extent these expenditures described in the Memorandum are considered syndication costs (such as the fees paid to brokers and broker-dealers, and the fees paid for printing the Prospectus and possibly all or a portion of the Managing General Partner’s management fee), they will be nondeductible by the Partnership. To the extent attributable to organization fees (such as the amounts paid for legal services incident to the organization of the Partnership), the expenditures may be amortizable over a period of not less than 180 months, commencing with the month the Partnership begins business, if the Partnership so elects; if no election is made, no deduction is available. Finally, to the extent any portion of the expenditures would be treated as "start-up," they could be amortized over a 180 month or longer period, provided the proper election was made.

The Managing General Partner has no opinion on the proper allocation of expenses among nondeductible syndication expenses, amortizable organization expenses, amortizable "start-up" expenditures, and currently deductible items, because the issues involve factual questions concerning both the nature of the services performed and to be performed and the reasonableness of amounts charged. If the IRS were to successfully challenge the Managing General Partner's allocations, a Partner's taxable income could be increased, thereby resulting in increased taxes and in liability for interest and penalties.

BASIS AND AT RISK LIMITATIONS

A Partner may deduct Partnership losses only to the extent these losses exceed the Partner's adjusted tax basis in the Partnership. Tax Code § 704(d). A Partner's initial adjusted tax basis in the Partnership will generally be equal to the cash invested increased by (i) additional amounts invested in the Partnership, including his share of net income, (ii) additional capital contributions, if any, and (iii) his share of Partnership borrowings, if any, based on the extent of his economic risk of loss for such borrowings. The adjusted tax basis will also generally be reduced by (i) his share of loss, (ii) his depletion deductions on his share of oil and gas income (until such deductions exhaust his share of the basis of property subject to depletion), (iii) distributions of cash and the adjusted basis of property other than cash made to him, and (iv) his share of reduction in the amount of indebtedness previously included in his basis. The adjusted tax basis cannot fall below zero. Treas. Reg. § 1.705-1(a). Upon a Partner's tax basis hitting zero, the Managing General Partner may allocate additional losses at its discretion.

In addition, Tax Code § 465 provides that, if an individual or a closely held C (i.e., regularly taxed) corporation engages in any activity to which Tax Code § 465 applies, any loss from that activity is allowed only to the extent of the aggregate amount with respect to which the taxpayer is "at risk" for such activity at the close of the taxable year. Tax Code § 465(a)(1). A closely held C corporation is a corporation, more than fifty percent (50%) of the stock of which is owned, directly or indirectly, at any time during the last half of the taxable year by or for not more than five (5) individuals. Tax Code §§ 465(a)(1)(B), 542(a)(2). For purposes of Tax Code § 465, a loss is defined as the excess of otherwise allowable deductions attributable to an activity over the income received or accrued from that activity. Tax Code § 465(d). Any such loss disallowed by Tax Code § 465 shall be treated as a deduction allocable to the activity in the first succeeding taxable year. Tax Code § 465(a)(2).

Tax Code § 465(b)(1) provides that a taxpayer will be considered as being "at risk" for an activity with respect to amounts including (i) the amount of money and the adjusted basis of other property contributed by the taxpayer to the activity, and (ii) amounts borrowed with respect to such activity to the extent that the taxpayer (I) is personally liable for the repayment of such amounts, or (II) has pledged property, other than property used in the activity, as security for such borrowed amounts (to the extent of the net fair market value of the taxpayer's interest in such property). No property can be considered as security if such property is directly or indirectly financed by indebtedness that is secured by property used in the activity. Tax Code § 465(b)(2). Further, amounts borrowed by the taxpayer shall not be considered if such amounts are borrowed (i) from any person who has an interest (other than an interest as a creditor) in such activity, or (ii) from a related person to a person (other than the taxpayer) having such an interest. Tax Code § 465(b)(3).

Related persons for purposes of Tax Code § 465(b)(3) are defined to include related persons within the meaning of Tax Code § 267(b) (that describes relationships between family members, corporations and shareholders, trusts and their grantors, beneficiaries and fiduciaries, and similar relationships), Tax Code § 707(b)(1) (that describes relationships between partnerships and their partners) and Tax Code § 52 (that describes relationships between persons engaged in businesses under common control). Tax Code § 465(b)(3)(C). Special ownership percentage limits of 10 percent or more can be made in determining who is a related person under Tax Code §§267 and 707. Tax Code §465(b)(3).

Finally, no taxpayer is considered at risk with respect to amounts for which the taxpayer is protected against loss through nonrecourse financing, guarantees, stop loss agreements, or other similar arrangements. Tax Code § 465(b)(4).

The Tax Code provides that a taxpayer must recognize taxable income to the extent that his "at risk" amount is reduced below zero. This recaptured income is limited to the sum of the loss deductions previously allowed to the taxpayer, less any amounts previously recaptured. A taxpayer may be allowed a deduction for the recaptured amounts included in his taxable income when he increases his amount "at risk" in a subsequent taxable year.

The Treasury has published proposed regulations relating to the at-risk provisions of Tax Code § 465. These proposed regulations provide that a taxpayer's at-risk amount will include "personal funds" contributed by the taxpayer to an activity. Prop. Treas. Reg. § 1.465-22(a). "Personal funds" and "personal assets" are defined in Prop. Treas. Reg. § 1.465-9(f) as funds and assets that (i) are owned by the taxpayer, (ii) are not acquired through borrowing, and (iii) have a basis equal to their fair market value.

In addition to a taxpayer's amount at risk being increased by the amount of personal funds contributed to the activity, the excess of the taxpayer's share of all items of income received or accrued from an activity during a taxable year over the taxpayer's share of allowable deductions from the activity for the year will also increase the amount at risk. Prop. Treas. Reg. § 1.465-22. A taxpayer's amount at risk will be decreased by (i) the amount of money withdrawn from the activity by or on behalf of the taxpayer, including distributions from a limited liability company taxed as a partnership, and (ii) the amount of loss from the activity allowed as a deduction under Tax Code § 465(a). Id.

The Partners will purchase the Partnership Units by paying cash to the Partnership. To the extent the cash contributed are "personal funds" of the Partners, the Partners should be considered at risk for those funds. The Managing General Partner believes that neither the at-risk rules nor the adjusted basis limitations will limit the deductibility of losses generated from the Partnership to the extent the contributed cash constitutes "personal funds."

PASSIVE LOSS AND CREDIT LIMITATIONS

A. Introduction

Tax Code § 469 provides that the deductibility of losses generated from passive activities will be limited for certain taxpayers. The passive activity loss limitations apply to individuals, estates, trusts, and personal service corporations as well as, to a lesser extent, closely held C corporations. Tax Code § 469(a)(2).

The definition of a "passive activity" generally encompasses all rental activities as well as all activities involving the conduct of a trade or business with respect to which the taxpayer does not "materially participate." Tax Code § 469(c). Notwithstanding this general rule, however, the term "passive activity" does not include "any working interest in any oil or gas property that the taxpayer holds directly or through an entity that does not limit the liability of the taxpayer with respect to such interest." Tax Code § 469(c)(3),(4).

A passive activity loss is the amount by which the aggregate losses from all passive activities for the taxable year exceed the aggregate income from all passive activities for such year. Tax Code § 469(d)(1).

Classifying an activity as passive will result in the income and expenses generated by that activity being treated as "passive" except to the extent that any of the income is "portfolio" income and except as otherwise provided in regulations. Tax Code § 469(e)(1)(A). Portfolio income is income from interest, dividends, royalties, or similar sources not derived in the ordinary course of a trade or business. Income that is neither passive nor portfolio is "net active income." Tax Code § 469(e)(2)(B).

With respect to the deductibility of passive activity losses, individuals and personal service corporations will be entitled to deduct such amounts only to the extent of their passive income whereas closely held C corporations (other than personal service corporations) can offset passive activity losses against both passive and net active income, but not against portfolio income. Tax Code § 469(a)(1), (e)(2). In calculating passive income and loss, however, all activities of the taxpayer are aggregated. Tax Code § 469(d)(1). Passive activity losses disallowed because of the above rules will be suspended and can be carried forward indefinitely to offset future passive (or passive and active, in the case of a closely held C corporation) income. Tax Code § 469(b).

Upon the disposition of an entire interest in a passive activity in a fully taxable transaction not involving a related party, any passive loss that was suspended by the provisions of the Tax Code § 469 passive activity rules are deductible from either passive or non-passive income. The deduction must be reduced, however, by the amount of income or gain realized from the activity in previous years. Tax Code § 469(g)

As noted above, a passive activity includes an activity with respect to which the taxpayer does not "materially participate." A taxpayer will be considered as materially participating in a venture only if the taxpayer is involved in the operations of the activity on a "regular, continuous, and substantial" basis. Tax Code § 469(h)(1). With respect to the determination as to whether a taxpayer's participation in an activity is material, temporary regulations issued by the IRS provide that, except for limited partners in a limited partnership, an individual will be treated as materially participating in an activity if and only if (i) the individual participates in the activity for more than 500 hours during such year, (ii) the individual's participation in the activity for the taxable year constitutes substantially all of the participation in such activity of all individuals for such year, (iii) the individual participates in the activity for more than 100 hours during the taxable year, and such individual's participation in such activity is not less than the participation in the activity of any other individual for such year, (iv) the activity is a trade or business activity of the individual, the individual participates in the activity for more than 100 hours during such year, and the individual's aggregate participation in all significant participation activities of this type during the year exceeds 500 hours, (v) the individual materially participated in the activity for 5 of the last 10 years, or (vi) the activity is a personal service activity and the individual materially participated in the activity for any 3 preceding years. Temp. Treas. Reg. § 1.469- 5T(a).

B. Additional General Partnership Units

The Managing General Partner has no opinion regarding whether the IRS will consider the Partner's participation to be "material" because of the fact-based material participation factors. However, the "working interest" exception to the passive activity rules applies without regard to the level of the taxpayer's participation. Nevertheless, the presence or absence of material participation may be relevant for purposes of determining whether the investment interest expense rules of Tax Code § 163(d) apply to limit the deductibility of interest incurred in connection with any borrowings of a Partner.

As noted above, the term "passive activity" does not include any working interest in any oil or gas property that the taxpayer holds directly or through an entity which does not limit the taxpayer's liability with respect to such interest. The Partnership will hold working interest in oil and gas properties. Further because the Additional General Partners are general partners, the Partnership will not operate to limit Additional General Partners' liability with respect to such working interest liabilities.

Temp. Treas. Reg. § 1.469-1T(e)(4)(v) describes an interest in an entity that limits a taxpayer's liability with respect to the drilling or operation of a well as (i) a limited partnership interest in a partnership in which the taxpayer is not a general partner, (ii) stock in a corporation, or (iii) an interest in any other entity that, under applicable state law, limits the interest holder's potential liability. For purposes of this provision, indemnification agreements, stop loss arrangements, insurance or any similar arrangements or combinations thereof are not considered in determining whether a taxpayer's liability is limited. Id. Some Partners may invest as Additional General Partners, not as Limited Partners or stockholders. Further, the liability of the Additional General Partners will not be otherwise limited under applicable state law.

The Joint Committee on Taxation's General Explanation of the Tax Reform Act of 1986 (the "Bluebook") indicates that a "working interest" is an interest with respect to an oil and gas property that is burdened with the cost of development and operation of the property, and that generally has characteristics such as responsibility for signing authorizations for expenditures with respect to the activity, receiving periodic drilling and completion reports and reports regarding the amount of oil extracted, voting rights proportionate to the percentage of the working interest possessed by the taxpayer, the right to continue activities if the present operator decides to discontinue operations, a proportionate share of tort liability with respect to the property and some responsibility to share in further costs with respect to the property in the event a decision is made to spend more than amounts already contributed. The Regulations define a working interest as "a working or operating mineral interest in any tract or parcel of land (within the meaning of § 1.612-4(a))." Treas. Reg. § 1.469-1(e)(4)(iv). Under Treas. Reg. § 1.614-2(b), an operating mineral interest is defined as:

> a separate mineral interest as described in § 614(a), in respect of which the costs of production are required to be taken into account by the taxpayer for purposes of computing the limitation of 50 percent of the taxable income from the property in determining the deduction for percentage depletion computed under § 613, or such costs would be so required to be taken into account if the . . . well . . . were in the production stage. The term does not include royalty interests or similar interests, such as production payments or net profits interests. For the purpose of determining whether a mineral interest is an operating mineral interest, "costs of production" do not include intangible drilling and development costs, exploration expenditures under § 615, or development expenditures under § 616. Taxes, such as production taxes, payable by holders of non-operating interests are not considered costs of production for this purpose. A taxpayer may not aggregate operating mineral interests and non-operating mineral interests such as royalty interests.

The Managing General Partner intends for the Partnership to acquire and hold only operating mineral interests, as defined in Tax Code § 614(d) and the regulations thereunder, and that none of the Partnership's revenues will be from non-working interests.

To the extent that the Partners have working interests in the activities of the Partnership for purposes of Tax Code § 469, the Managing General Partner believes that a Partner's Interest(s) in the Partnership generally will not be considered a passive activity within the meaning of Tax Code § 469 and losses generated while such Partner Interest(s) are held will not be limited by the passive activity provisions.

C. Unrelated Business Taxable Income

Unrelated Business Taxable Income ("UBTI") is income on which a tax-exempt entity (an organization that generally is exempt from Federal income tax such as a pension plan or charity) is required to pay tax. UBTI income derives from a trade or business regularly carried by the tax-exempt organization that is not substantially related to the exempt organization's exempt function. (e.g., operation of a macaroni factory by a pension trust or the operation of an equipment rental business by a hospital). Investment type income generally is not UBTI. Investment income includes dividends, interest, annuities, royalties, and most rents from real property. However, if the investment income derives from an enterprise financed with debt, then the income can be UBTI. Please note that the Partnership Agreement does not permit the Partnership to incur debt.

INTANGIBLE DRILLING AND DEVELOPMENT COSTS DEDUCTIONS

Generally, taxpayers cannot deduct capital expenditures under Tax Code § 263(a). See also Treas. Reg. § 1.461-1(a)(2). In Indopco, Inc. v. Commissioner, 503 U.S. 79 (1992), the Supreme Court said that the costs should be capitalized when they provide benefits that extend beyond one tax year. However, Congress granted to the Treasury Secretary the authority to prescribe regulations allowing taxpayers to expense, rather than capitalize, intangible drilling and development costs ("IDC"). Tax Code § 263(c). The Treasury Regulations generally state that the option to expense IDC applies only to expenditures for drilling and development items without salvage value. Treas. Reg. § 1.612-4.

The Partnership (not the Partner) may opt to expense or capitalize IDC in the year in which the deduction is to be taken. Tax Code § 703 and Treas. Reg. § 1.703-1(b). The Managing General Partner plans for the Partnership to elect to expense IDC in accordance with Treas. Reg. § 1.612-4. This generally means that Partners will be entitled to deduct IDC against any form of income in the year in which the investment is made, provided drilling operations on the Partnership Wells are commenced within the first ninety days of the following year; and that Partners will be entitled to deduct IDC against passive income under the same terms. Passive income credit limitations and the alternative minimum tax may limit the benefit of an IDC deduction.

A. Classification of Costs

IDC generally consists of costs with no salvage value. Treas. Reg. § 1.612-4(a) provides IDC examples, including all amounts paid for labor, fuel, repairs, hauling, and supplies, or any of them, that are used (i) in the drilling, shooting, and cleaning of wells, (ii) in such clearing of ground, draining, road making, surveying, and geological works as are necessary in the preparation for the drilling of wells, and (iii) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. The IRS, in Rev. Rul. 70-414, 1970-2 C.B. 132, limits IDC items. The ruling states that the Managing General Partner cannot elect to expense the following under Treas. Reg. §1.612-4(a): (i) oil well pumps (upon initial completion of the well), including the necessary housing structures; (ii) oil well pumps (after the well has flowed for a time), including the necessary housing structures; (iii) oil well separators, including the necessary housing structures; (iv) pipelines from the wellhead to oil storage tanks on the producing lease; (v) oil storage tanks on the producing lease; (vi) salt water disposal equipment, including any necessary pipelines; (vii) pipelines from the mouth of a gas well to the first point of control, such as a common carrier pipeline, natural gasoline plant, or carbon black plant; (viii) recycling equipment, including any necessary pipelines; and (ix) pipelines from oil storage tanks on the producing leasehold to a common carrier pipeline.

The IRS can second guess the Partnership's choice to expense certain costs as IDC. In Revenue Ruling 73-211, the IRS held to the extent that a turnkey drilling price exceeds costs that would have been incurred in an arm's length transaction, such excess is to be treated as a capitalized cost of the working interest. See also Bernuth v. Comm., 57 TC 225, (1971) aff'd, 470 F.2d 710 (2nd Cir. 1972). To the extent the Partnership's drilling price meets these reasonable price standards and to the extent such amounts are not allocable to tangible property, leasehold costs, and the like, the amounts paid to the Managing General Partner under the drilling contract should qualify as IDC and should be deductible at the time described below under "Timing of Deductions." That portion of the amount paid to the Managing General Partner that is more than the amount that would be charged by an independent driller under similar conditions will not qualify as IDC and will be required to be capitalized.

No assurance can be made that the IRS will agree with this fact-based assessment or agree with the Managing General Partner's determination that certain project expenditures that can be expensed rather than capitalized.

We anticipate that, to the extent allowable by tax law, the Partnership will be responsible for paying those drilling and completion expenses that may be expensed as IDC up to the full extent of its working interest percentage.

B. Timing of Deductions

Partnerships may expense IDCs under Tax Code § 263(c) and Treas. Reg. § 1.612-4. If the Partnership expenses the IDC, the taxpayer may elect to follow that choice or to capitalize all or a part of the IDC and amortize the same on a straight-line basis over a sixty-month period, beginning with the taxable month in which such expenditure is made. Tax Code §§ 59(e)(1) and (2)(c).

The timing of the taxpayer's IDC deduction depends on the taxpayer's method of accounting. The Partnership will use the accrual method of accounting and will recognize income upon the occurrence of all events that accurately fix the right to receive and the amount of this income. Treas. Reg. § 1.451-1(a). The Partnership will also recognize expenses upon the occurrence of all events that accurately fix the right to obligation to pay, and the amount obligated. Treas. Reg. § 1.461-1(a)(2). Further, Tax Code § 461(h)(1) provides that ". . . the all events test shall not be treated as met any earlier than when economic performance with respect to such item occurs."

For oil and gas wells, the Tax Code states that "economic performance" occurs within a tax year if the drilling of the well starts before the close of the 90th day after the close of that tax year. Tax Code § 461(i)(2). However, the maximum allowed deduction for prepaid expenses under this exception is limited to the amount of the Partner's "cash basis" in the Partnership. Tax Code § 461(i)(2)(B)(i). This "cash basis" equals the Partner's adjusted basis in the Partnership, determined without regard to (i) any liability of the Partnership or (ii) any amount borrowed by the Partner relating to the Partnership, provided that the Partnership, its promoter, organizer, or management arranged the loan or that the loan was secured by Partnership assets. Tax Code § 461(i)(2)(C). Further, the Managing General Partner believes that the Partnership will not have any such liability referred to in Tax Code § 461(i)(2)(C), and the Partners will not so incur any such debt to result in the application of the limiting provisions contained in Tax Code § 461(i)(2)(B)(i).

Caselaw also limits the deductibility of prepaid IDC. Prepaid IDC is deductible when paid if (i) the expenditure constitutes a payment that is not merely a deposit, (ii) the payment is made for a business purpose, and (iii) deductions attributable to such outlay do not result in a material distortion of income. See Keller v. Commissioner, 79 T.C. 7 (1982), aff'd, 725 F.2d 1173 (8th Cir. 1984), Rev. Rul. 71-252, 1971-1 C.B. 146, Pauley v. U.S., 63-1 U.S.T.C. paragraph 9280 (S.D. Cal. 1963), Rev. Rul. 80-71, 1980-1 C.B. 106, Jolley v. Commissioner, 47 T.C.M. 1082 (1984), Dillingham v. U.S., 81-2 U.S.T.C. paragraph 9601 (W.D. Okla. 1981), and Stradlings Building Materials, Inc. v. Commissioner, 76 T.C. 84 (1981). Generally, these requirements may be met by a showing of a legally binding obligation (i.e., the payment was not merely a deposit), of a substantial legitimate business purpose for the payment, that performance of the services was required within a reasonable time, and of an arm's-length price. Similar requirements apply to cash basis taxpayers seeking to deduct prepaid IDC.

Intangible costs deductions for 2023 will only be available for commencing drilling operations on a Partnership Wells by no later than March 30, 2024, if the expenses have been prepaid by December 31, 2023. Intangible costs deductions for 2024 will only be available for commencing drilling operations on a Partnership Wells by no later than March 30, 2025, if the expenses have been prepaid by December 31, 2024.

The IRS has challenged the timing of the deduction of IDC when the wells giving rise to such deduction have been completed in a year after the year of prepayment. The decisions noted above hold that prepayments of IDC by a cash basis taxpayer are, under certain circumstances, deductible in the year of prepayment if some work is performed in the year of prepayment even though the well is not completed that year.

In Keller v. Commissioner, supra, the Eighth Circuit Court of Appeals applied a three-part test for determining the current deductibility of prepaid IDC by a cash basis taxpayer, namely whether (i) the expenditure was a payment or a mere deposit, (ii) the payment was made for a valid business purpose and (iii) the prepayment resulted in a material distortion of income. The facts in that case dealt with two different forms of drilling contracts: footage or day-work contracts and turnkey contracts. Under the turnkey contracts, the prepayments were not refundable in any event, but in the event, work was stopped on one well the remaining unused amount would be applied to another well to be drilled on a turnkey basis. Contrary to the IRS's argument that this substitution feature rendered the payment a mere deposit, the court in Keller concluded that the prepayments were indeed "payments" because the taxpayer could not compel a refund. The court further found that the deduction clearly reflected income because under the unique characteristics of the turnkey contract the taxpayer locked in the price and shifted the drilling risk to the contractor, for a premium, effectively getting its bargained for benefit in the year of payment. Therefore, the court concluded that the cash basis taxpayers in that case properly could deduct turnkey payments in the year of payment. With respect to the prepayments under the footage or day-work contracts, however, the court found that the payments were mere deposits on the facts of the case, because the Partnership had the power to compel a refund. The court was also unconvinced as to the business purpose for prepayment under the footage or day-work contracts, primarily because the testimony indicated that the drillers would have provided the required services with or without prepayment.

The IRS has adopted the position that the relationship between the parties may provide evidence that the drilling contract between the parties requiring prepayment may not be a bona fide arm's-length transaction, in which case a portion of the prepayment may be disallowed as being a "non-required payment." § 4236, Internal Revenue Service Examination Tax Shelters Handbook (6- 27-85). A similar position is taken by the IRS in the Tax Shelter Audit Technique Guidelines. Internal Revenue Service Examination Tax Shelter Handbook.

The IRS has formally adopted its position on prepayments to related parties in Revenue Ruling 80-71, 1980-1 C.B. 106. In this ruling, a subsidiary corporation, that was a general partner in an oil and gas partnership, prepaid the partnership's drilling and completion costs under a turnkey contract entered with the corporate parent of the general partner. The agreement did not provide for any date for commencing drilling operations and the contractor, which did not own any drilling equipment, was to arrange for the drilling equipment for the wells through subcontractors. Revenue Ruling 71-252, supra, was factually distinguished on the grounds of the business purpose of the transaction, immediate expenditure of prepaid receipts, and completion of the wells within two and one-half months. Rev. Rul. 80-71 found that the prepayment was not made in accordance with customary business practice and held on the facts that the payment was deductible in the tax year that the related general contractor paid the independent subcontractor.

However, in Tom B. Dillingham v. United States, supra, the court held that, on the facts before it, a contract between related parties requiring a prepaid IDC did give rise to a deduction in the year paid. In that case, Basin Petroleum Corp. ("Basin") was the general partner of several drilling partnerships and served as the partnership operator and general contractor. As general contractor, Basin was to conduct the drilling of the wells at a fixed price on a turnkey basis under an agreement that required payment prior to the end of the year in question. The stated reason for the prepayment was to provide Basin with working capital for the drilling of the wells and to temporarily provide funds to Basin for other operations. The agreement required drilling to commence within a reasonable period, and all wells were completed within the following year. Some of the wells were drilled by Basin with its own rigs and some were drilled by subcontractors. The court stated:

> The fact that the owner and contractor is the general partner of the partnership-owner does not change this result where, as here, the Plaintiffs have shown that prepayment was required for a legitimate business purpose and the transaction was not a sham to merely permit Plaintiff to control the timing of the deduction. IRC, Sec. 707(a). Plaintiffs were entitled to rely upon Revenue Ruling 71-252 by reason of Income Tax Regulations 26 C.F.R. § 601.601(d)(2)(v)(e).

Notwithstanding the foregoing, the Managing General Partner can make no assurance can be given that the IRS will not challenge the current deduction of prepaid IDC. If the IRS were successful with such challenge, the Partners' deductions for IDC would be deferred to later years.

The timing of the deductibility of prepaid IDC is inherently a factual determination that is to a large extent predicated on future events. The operating agreement to be entered into with an Operator by the Managing General Partner will be duly executed by and delivered to the Partnership, and the Managing General Partner as attorney-in-fact for the Partners and will govern the drilling, and, if warranted, the completion of Partnership Wells.

C. Allocation of IDC Deductions

The intangible drilling and completion costs will be allocated pro rata basis within the Partnership based on percentage ownership. In Levy v. Commissioner, 732 F.2d 1435 (9th Cir. 1984), the Ninth Circuit Court of Appeals allowed a taxpayer who had invested in oil and gas properties by paying both cash and a note to allocate the IDCs first to the cash portion of the investment that allowed for current-year deduction, and secondarily to the note portion of the investment, that did not allow for current-year deduction. The IRS had argued that the IDC should have been allocated on a pro rata basis against both forms of payment. Subsequently, the IRS's Chief Counsel released an Action on Decision statement. The Chief Counsel said that the IRS would not appeal this decision but disagreed with it. The Action on Decision stated that the IRS's position was that a taxpayer cannot allocate intangible drilling costs against different types of payment except in a pro rata fashion. IRS AOD 1984-055 (September 13, 1984).

The Managing General Partner believes that the pro rata allocation of intangible drilling and completion costs within the Partnership comply with the Chief Counsel's pro rata distribution requirement. But the Managing General Partner can make no assurance that the IRS will agree with this position.

D. Recapture of IDC

The IRS can recapture expensed IDC as ordinary income upon certain transfers of oil and gas property interests. IDC previously deducted that were directly or indirectly allocable to the property and that would have been included in the adjusted basis of the property is recaptured to the extent of any gain realized upon the disposition of the property. Treasury regulations provide that recapture is determined at the Partner level (subject to certain anti-abuse provisions). Treas. Reg. § 1.1254-5(b). If the Partnership transfers only a portion of its whole oil and gas property interest against which IDC have been allocated, the IDC related to the whole property can be recaptured to the extent that a gain was realized on the partial sale of the property. If the Partnership transfers an undivided interest in a property, such as a fractional working interest (as opposed to the disposition of a portion of the property), a proportionate part of the IDC with respect to the property is treated as allocable to the transferred undivided interest to the extent of any realized gain. Treas. Reg. § 1.1254-1(c).

The Managing General Partner strongly recommends that Additional General Partners consult their tax advisors in considering whether to convert to being a Limited Partner as provided for in the Limited Partnership Agreement. There is a risk that upon such conversion that the IRS may seek to recapture IDC deductions that would not have been available to Limited Partners. Accordingly due caution should be used when making the conversion decision.

DEPLETION DEDUCTIONS

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. In the case of partnership taxed as partnerships, the depletion allowance must be computed separately by each partner and not by the partnership. Tax Code § 613A(c)(7)(D). Notwithstanding this requirement, however, the Partnership, pursuant to § 5.1(d) of the Partnership Agreement, will compute a "simulated depletion allowance" at the Partnership level, solely for the purposes of maintaining Capital Accounts. Tax Code §§ 613A(d)(2) and 613A(d)(4).

Cost depletion for any year is determined by multiplying the number of units (e.g., 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. See Treas. Reg. § 1.611-2(a). In no event can the cost depletion exceed the adjusted basis of the property to which it relates.

Percentage depletion is generally available only with respect to the domestic oil and gas production of certain "independent producers." To qualify as an independent producer, the taxpayer, either directly or through certain related parties, may not be involved in the refining of more 50,000 barrels of oil (or equivalent of gas) on any day during the taxable year or in the retail marketing of oil and gas products exceeding $5 million per year in the aggregate.

In general, (i) component members of a controlled group of corporations, (ii) corporations, trusts, or estates under common control by the same or related persons and (iii) members of the same family (an individual, his spouse and minor children) are aggregated and treated as one taxpayer in determining the quantity of production (barrels of oil or cubic feet of gas per day) qualifying for percentage depletion under the independent producer's exemption. Tax Code § 613A(c) (8). No aggregation is required among Partners or between a Partner and a Partnership. An individual taxpayer is related to an entity engaged in refining or retail marketing if he owns 5% or more of such entity. Tax Code § 613A(d)(3).

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 (computed without regard to percentage depletion and net operating loss and capital loss carrybacks). Tax Code §§ 613(a) and 613A(d)(1). For purposes of computing the percentage depletion deduction, "gross income from the property" does not include any lease bonus, advance royalty, or other amount payable without regard to production from the property. Tax Code § 613A(d)(5). Depletion deductions reduce the taxpayer's adjusted basis in the property. However, unlike cost depletion, deductions under percentage depletion are not limited to the adjusted basis of the property; the percentage depletion amount continues to be allowable as a deduction after the adjusted basis has been reduced to zero.

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. Tax Code § 613A(c)(3) and (4). In computing his individual limitation, a Partner will be required to aggregate his share of the Partnership's oil and gas production with his share of production from all other oil and gas investments. Tax Code § 613A(c). Taxpayers who have both oil and gas production may allocate the deduction limitation between the two types of production.

The availability of a depletion and any limits on such deductions, whether cost or percentage, will be determined separately by each Partner. Each Partner must separately keep records of his share of the adjusted basis in an oil or gas property, adjust such share of the adjusted basis for any depletion taken on such property, and use such adjusted basis each year in the computation of his cost depletion or in the computation of his gain or loss on the disposition of such property. These requirements may place an administrative burden on a Partner. For properties placed in service after 1986, depletion deductions, to the extent they reduce the basis of an oil and gas property, are subject to recapture under Tax Code § 1254.

The Managing General Partner will provide information relating to depletion to the Partners, but the election of the type of and amount of depletion will be made by the Partners. Thus, the Managing General Partner has no opinion on the tax treatment of the depletion allowance.

Publicly Traded Partnerships

The Managing General Partner does not expect the Partnership to ever become a publicly traded partnership, so prospective partners should consult their tax advisors to learn about the taxation of publicly traded partnerships. But, in any event, income and losses from publicly traded partnerships will be generally treated as portfolio income or losses under the Tax Code unless the Partnership meets certain parameters set out in the Tax Code. So, investors should understand that, should this Partnership become a publicly traded partnership, their ability to offset income or losses from this Partnership, could be very limited.

Texas Severance Tax

Texas imposes a severance tax on oil, gas, and condensate production. All hydrocarbon production for the benefit of the Partnership will be subject to these taxes. The baseline Texas severance taxes are:

1) Gas severance tax = 7.5% of market value of gas produced and saved;
2) Oil severance tax = 4.6% of market value of oil produced; and
3) Condensate tax = 4.6% of market value.

Additionally, Texas has a "regulatory fee" of $.000667 for thousand cubic feet of gas produced.

New Mexico Severance Tax

New Mexico imposes a severance tax on all oil, gas and condensate products severed and sold at the baseline rate of 3.75%. Hydrocarbon production for the benefit of the Partnership will be subject to these taxes.

Disclaimer

Please consult your tax advisor for specific information relating to the tax advantages available to partners. This is not tax advice as we are not a licensed tax professional. This information is for reference purposes only and can be easily verified by a licensed tax professional.

INVESTORS SUBJECT TO ERISA

The Partnership Units are likely to be treated as equity interests. Thus, ERISA will likely apply to investors which are employee benefit plans or trusts subject to ERISA, or Keogh Plan subject to the Internal Revenue Code, and such investors should consider the risks involving ERISA and the Internal Revenue Code.

EACH PROSPECTIVE INVESTOR SHOULD CONSULT WITH ITS OWN COUNSEL IN ORDER TO UNDERSTAND THE ERISA ISSUES AFFECTING THE MANAGING GENERAL PARTNERSHIP UNITS AND THE INVESTOR.

U.S. Department of Labor regulations relating to ERISA state that investments by a plan in the equity of a non-public business entity that is not a registered investment company may cause the assets of that entity to be treated as plan assets subject to ERISA's fiduciary rules under certain circumstances, that is, if the business entity is not an operating company and 25% or more of the business entity's equity assets are held by benefit plans subject to ERISA. The Partnership does not anticipate that 25% or more of its equity will be held by benefit plans governed by ERISA.

If Partnership assets were regarded as "plan assets" of an ERISA or Keogh plan, the Partnership and/or the Managing General Partner could be a "fiduciary" ERISA or the Internal Revenue Code for the Plan with corresponding obligations and liabilities. Moreover, the Partnership and/or the Managing General Partner could be subject to ERISA's requirements for plan fiduciaries, which include rules restricting related-party transactions and conflicts of interest.

If the Partnership is determined to be a ERISA or Keogh Plan fiduciaries, it must (1) evaluate how the Partnership Unit investment would impact the Plan by considering whether the investment is reasonably designed to further the Plan's purposes, (2) examine the Partnership Units' risk and return factors, (3) consider the Plan portfolio's diversification needs, (4) evaluate the Partnership Units' lack of liquidity and relative to the anticipated cash flow needs of the Plan,
(5) consider the projected return of the total portfolio to the Plan's objectives, (6) determine whether investment in the Partnership is permitted under governing Plan documents, and (7) consider the lack of redemption rights and limited transferability.

The fiduciaries of each Plan proposing to purchase the Partnership Units will be required to represent that they have been informed of and understand the Partnership's investment objectives, policies, and strategies, and that the decision to invest Plan assets in the Partnership Units is consistent with the provisions of ERISA that require diversification of Plan assets and impose other fiduciary responsibilities. Further, tax benefits such as intangible cost and depletion deductions will likely be of little or no benefit to ERISA and Keogh plans.

Exempt organizations should consider the applicability to them of the provisions relating to "unrelated business taxable income."

Finally, ERISA plans and ERISA-covered accounts should carefully consider the merits of investing in the Partnership as any intangible drilling cost or depletion tax deductions will likely not provide a benefit to such plans or accounts.

CONFLICTS OF INTEREST AND TRANSACTIONS WITH THE MANAGING GENERAL PARTNER

Conflicts of Interest

- 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 not affiliated with the Managing General Partner or Partnership.

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

The Partnership is subject to various conflicts of interest arising out of its relationship with the Managing General Partner. These conflicts include, but are not limited to, the following:

Future Programs by the Operator, the Managing General Partner, and their Affiliates. The Operator, the Managing General Partner and their Affiliates have the right and expects to continue to organize and manage oil and gas drilling programs in the future like the Partnership and may conduct operations now and in the future jointly or separately, on its own behalf or for other private or public investors. To the extent Affiliates of the Managing General Partner invest in the Partnership or other partnerships or entities sponsored by the Managing General Partner, conflicts of interest will arise.

Fiduciary Responsibility of the Managing General Partner. The Managing General Partner is accountable to the Partnership as fiduciary and consequently has a duty to exercise good faith and to deal fairly with the Partners in handling the affairs of the Partnership. While the Managing General Partner will try to avoid conflicts of interest to the extent possible, such conflicts nevertheless may occur and, in such event, the actions of the Managing General Partner may not be the most advantageous to the Partnership and could fall short of the full exercise of such fiduciary duty. In the event the Managing General Partner should breach its fiduciary responsibilities, a Partner would be entitled to an accounting and to recover any economic losses caused by such Breach.

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

Managing General Partner's Interest. Although the Managing General Partner believes that its interest in Partnership profits, losses and cash distributions is equitable (See "Participation in Costs and Revenues"), such interest was not determined by arm's-length negotiation.

Conflicts with Other Programs. The Managing General Partner realizes that its conduct and the conduct of its Affiliates in connection with the other drilling programs could give rise to a conflict of interest between the position of the Managing General Partner as the Managing General Partner and the position of the Managing General Partner or one of its Affiliates as general partner or sponsor of such additional programs. In resolving any such conflicts, 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.

Notwithstanding any provision to the contrary, the Managing General Partner and its Affiliates may not profit by drilling in contravention of their fiduciary obligations to the Partners. Any services not otherwise described in this Memorandum for which the Managing General Partner or any of its Affiliates are to be compensated will be embodied in a written contract which precisely describes the services to be rendered and the compensation to be paid.

All benefits from marketing arrangements or other relationships affecting the property of the Managing General Partner or its Affiliates and the Partnership will be fairly and equitably apportioned according to the respective interest of each.

FIDUCIARY RESPONSIBILITIES AND INDEMNIFICATION OF THE MANAGING GENERAL PARTNER

- The Managing General Partner is accountable to the Partnership as a fiduciary and must exercise good faith and integrity in respecting the Partnership's affairs.

- The Partnership Agreement includes provisions indemnifying the Managing General Partner against liability for losses suffered by the Partnership resulting from actions by the General Partner.

The Managing General Partner is accountable to the Partnership as a fiduciary and consequently must exercise good faith and integrity in handling Partnership affairs. Under Texas law, the

Managing General Partner would be required to prudently supervise and direct the activities of the Partnership. Moreover, the Managing General Partner must always act in the reasonable best interests of the Partnership and the Partners. Prospective Partners who have questions concerning the responsibilities of the Managing General Partner should consult their own counsel.

The Partnership Agreement provides for indemnification of the Managing General Partner against liability for losses arising from Partnership affairs provided that the Managing General Partner did not act or fail to act with fraud, bad faith, gross negligence, or willful misconduct.

In the U.S. Securities and Exchange Commission's opinion, indemnification provisions indemnify for liabilities arising under the Securities Act of 1933 and the Securities Exchange Act of 1934 are against public policy, and, therefore, unenforceable. Consequently, unless Courts rule otherwise, the Managing General Partner will not be indemnified for liabilities arising under Federal securities laws unless (1) there has been a successful adjudication on the merits of each count involving securities law violations or (2) such claims have been dismissed with prejudice on the merits by a court of competent jurisdiction or (3) a court of competent jurisdiction approves a settlement of such claims and finds that indemnification of the settlement and the related costs should be made after having been advised of U.S. Securities and Exchange Commission's and relevant state securities administrators' positions on indemnification of securities violations claims. A successful indemnification claim would deplete Partnership assets by the amount paid. A Limited Partner may have a narrower scope of legal actions due to the indemnification provision than if the indemnification provision was omitted.

LEGAL PROCEEDINGS

The Managing General Partner knows of no litigation pending or threatened to which the Managing General Partner or the Partnership is subject or may be a party, and no such proceedings are known to be contemplated by governmental authorities or other parties.

SUMMARY OF THE PARTNERSHIP AGREEMENT

The rights and obligations of the Partners will be governed by the Limited Partnership Agreement ("Partnership Agreement") in the form attached to this Memorandum as Exhibit B. Each prospective investor, together with their personal advisers, should carefully study the Partnership Agreement in its entirety before submitting a Subscription. The following statements concerning the Partnership Agreement are merely an outline, do not purport to be complete and in no way amend or modify the Partnership Agreement. References to sections below refer to sections of the Partnership Agreement.

Responsibility of the Managing General Partner

The Managing General Partner will have the exclusive management and control of all aspects of the business of the Partnership (Sections 4.1 and 4.2). No Limited Partner or Additional General Partner will have any voice in the day-to-day business operations of the Partnership (Section 4.1). The Managing General Partner is authorized to delegate and subcontract its duties under the Partnership Agreement to others, including entities related to it (Section 4.2).

Liability of Limited Partners (not applicable to Additional General Partners)

The Partnership will be governed by the Texas Business Organizations Code under which a Limited Partner's liability for the obligations of the Partnership will be limited to the Limited Partners' Capital Contributions, the Limited Partners' shares of Partnership assets and for the return of any part of Partnership Capital Contributions for a period of one year after such return (or six years in the event such return is in violation of the Partnership Agreement), but only to the extent necessary to discharge the Partnership's liabilities to creditors who extended credit to the Partnership prior to such return. Additional General Partners will not have such limitation of their liabilities. A Limited Partner will not otherwise be liable for the obligations of the Partnership unless, in addition to the exercise of the Limited Partner's rights and powers as a Limited Partner, such person takes part in the control of the business of the Partnership. Under Section 3.2 of the Partnership Agreement, the Limited Partners, however, are obligated to make additional Capital Contributions if the Managing General Partner determines such capital is needed for the Partnership's business.

Liability of Additional General Partners (not applicable to Limited Partners)

Additional General Partners are liable for the obligations of the Partnership on a joint and several basis. This means that they may be liable for the entire amount of the obligations of or claims against the Partnership regardless of whether any of the other Partners have similar obligations. If other Partners do not pay their share of obligations and claims, the Additional General Partners could be liable for the shortfall.

Conversion from an Additional General Partner to a Limited Partner

On January 1 of the year immediately following the calendar year of the Partnership with respect to which the Managing General Partner has determined that the at least 90% of funds paid to the Partnership by the Investor Partners as a result of the offer and sale of Units shall have been expended the Units held by the Additional General Partners may be converted to Limited Partner Units, unless the Managing General Partner determines that such conversion at that time would not be in the best interests of the General Partners or the Partnership.

As stated in the "Tax Aspects" of this Memorandum, the Managing General Partner recommends that Additional General Partners consult their tax advisers as to the possible recapture of intangible drilling cost deductions because of such a conversion.

Allocations and Distributions

General: Profits and losses are to be allocated and cash is to be distributed in the manner described in the section entitled "Allocations of Profits and Losses." (See Section VI).

Liquidating Distributions: Liquidating distributions (after the payment of all Partnership liabilities) will be made to the Partners in accordance with their respective Capital Accounts (Section 9.4).

Voting Rights

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 General Partner will have seventy-five (75%) of the Partnership's voting interest. This means that the Limited Partners and Additional General Partners will not have a vote that could affect the Partnership's decisions unless the Managing General Partner chooses to abstain from voting.

Books and Records

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

Retirement of the Managing General Partner

If the Managing General Partner desires to withdraw from the Partnership for whatever reason, it may do so by giving written notice to the Partners. This will terminate the Partnership unless reconstituted by the remaining Partners.

Term and Winding-up

The Partnership will commence winding-up upon the occurrence if:

(a) the written consent of the Managing General Partner and Limited Partners representing most of the Partnership Units requests the Winding-Up of Partnership activities; or

(b) The Managing General Partner's resignation, retirement, adjudication of incapacity, withdrawal, removal, dissolution, liquidation, or bankruptcy, unless a successor Managing General Partner is selected by Partners owning a majority of the then outstanding Partnership Units within 90 days after such event to reconstitute the Partnership.

Indemnification

The Managing General Partner will be entitled to reimbursement and indemnification for all expenditures made (including amounts paid in settlement of claims) or losses or judgments suffered by it arising from the Partnership, or its property, business, or affairs to the fullest extent allowed by law, provided that the expenditures were not the result of gross negligence or willful misconduct on the part of the Managing General Partner.

Reports to Partners

The Managing General Partner will furnish to the Partners a statement for that year of each Investor Partner's share of the Profits and Losses. The Managing General Partner shall also furnish summary reports on showing the status of the drilling and completion of the Partnership Wells until drilling and completion activities are completed.

Power of Attorney

Each Partner will grant to the Managing General Partner a power of attorney to execute certain documents deemed by the Managing General Partner to be necessary or convenient to the Partnership's business or required in connection with the qualification and continuance of the Partnership (Section 14.1).

Other Provisions

Other provisions of the Partnership Agreement are summarized in this Memorandum under the headings "Terms of the Offering," "Sources and Application of Proceeds," "Management," "Fiduciary Responsibilities and Indemnification of the Managing General Partner," and "Transferability of Units." The attention of prospective investors is directed to these sections.

TRANSFERABILITY OF UNITS

The transferability of the Units is very limited and no market for the Units will develop. An investment in the Partnership should be considered an illiquid investment. Investors may not be able to sell their Units without the Managing General Partner's consent and may be required to produce a legal opinion relating to transferability. The Partnership intends that it will not be treated as "publicly traded partnership." Consequently, the Managing General Partner intends to seek to prevent the Partnership Units from trading on any established securities market.

OTHER MATTERS

This Memorandum does not propose to restate all the relevant provisions of the documents referred to or relevant to the matters discussed herein. All these documents must be read for a thorough understanding of the terms of all matters relevant to the purchase of Units. Each prospective investor is invited to ask questions of, and receive answers from, authorized representatives of the Managing General Partner, and may inspect the books and records of the Partnership at any reasonable time, in order to obtain such information concerning the terms and conditions of the offering, to the extent the Partnership possesses the same or can obtain it without unreasonable effort or expense, as such prospective investor deems necessary to verify the accuracy of the information referred to in this Memorandum. The Managing General Partner will maintain at its office a list of the names and addresses of all Partners.

Attention is directed to the Partnership Agreement and other Exhibits to this Memorandum for a full description of matters which may be described summarily in this Memorandum, or which may not be included in the text of this Memorandum.

FINANCIAL STATUS OF THE PARTNERSHIP

PB Non-op Drilling LP is a Texas limited partnership formed under Texas law on September 1, 2023, and as of the date of this offering is not capitalized.

FINANCIAL INFORMATION FOR THE MANAGING GENERAL PARTNER

PB Non-op Drilling GP, LLC is a Texas limited liability company formed on September 1, 2023. It will not be making a material capital contribution to the Partnership. PB Non-op Drilling LP is the first business venture it has sponsored.

OTHER DOCUMENTS

The Managing General Partner values its relationship with its investing partners. It takes every precaution it can with client information subject, of course, to government regulation. The Partnership's policies forbid any dissemination of client information both inside and outside the Partnership.

PAYMENT

Payment by investor may be made by check, wire transfer, or cashier's check. The Partnership follows various federal regulations and may have to provide information to government agencies where the investment is made by cash, wire transfer or other means outside the normal course of commerce. The Managing General Partner may have to provide information to government agencies where the investment is made by cash or other means outside the normal course of commerce.

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Exhibit A

Certificate of Formation

PB Non-op Drilling LP

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