UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2021
or
☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition Period from ________ to ________
Commission File Number: 000-50175

DORCHESTER MINERALS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**81-0551518**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

3838 Oak Lawn Avenue, Suite 300
Dallas, Texas 75219
(Address of principal executive offices) (Zip Code)

(214) 559-0300
(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units Representing Limited Partnership Interest	DMLP	NASDAQ Global Select Market

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Title of Class
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☒
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).Yes ☒ No ☐
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," “accelerated filer,” “smaller reporting company," and “emerging growth company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒
Smaller reporting company ☒ Emerging growth company ☐
If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐
Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act.). Yes ☐ No ☒

The aggregate market value of the common units held by non-affiliates of the registrant (treating all managers, executive officers and 10% unitholders of the registrant as if they may be affiliates of the registrant) was approximately $549,852,929 as of the last business day of the registrant’s most recently completed second fiscal quarter, based on $16.85 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.
Number of Common Units outstanding as of February 24, 2022: 36,984,774

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the registrant's 2022 Annual Meeting of Unitholders to be held on May 18, 2022, are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2021.

TABLE OF CONTENTS

PART I.

ITEM 1. BUSINESS

General

Dorchester Minerals, L.P. is a publicly traded Delaware limited partnership that commenced operations on January 31, 2003, upon the combination of Dorchester Hugoton, Ltd., Republic Royalty Company, L.P. and Spinnaker Royalty Company, L.P. Dorchester Hugoton was a publicly traded Texas limited partnership, and Republic and Spinnaker were private Texas limited partnerships. We have established a website at www.dmlp.net that contains the last annual meeting presentation and a link to the NASDAQ website. You may obtain all current filings free of charge at our website. We will provide electronic or paper copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished to the Securities and Exchange Commission ("SEC") free of charge upon written request at our executive offices. In this report, the term "Partnership," as well as the terms "us," "our," "we," and "its" are sometimes used as abbreviated references to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities.

Our general partner is Dorchester Minerals Management LP, which is managed by its general partner, Dorchester Minerals Management GP LLC. As a result, the Board of Managers of Dorchester Minerals Management GP LLC exercises effective control of the Partnership. In this report, the term "General Partner" is used as an abbreviated reference to Dorchester Minerals Management LP. Our General Partner also controls and owns, directly and indirectly, all of the Partnership interests in Dorchester Minerals Operating LP and its general partner. Dorchester Minerals Operating LP owns working interests and other properties underlying our Net Profits Interest (or "NPI"), provides day-to-day operational and administrative services to us and our General Partner, and is the employer of all the employees who perform such services. In this report, the term "Operating Partnership" is used as an abbreviated reference to Dorchester Minerals Operating LP. Our General Partner and the Operating Partnership are Delaware limited partnerships, and the general partners of their general partners are Delaware limited liability companies.

On September 30, 2020, the Partnership and affiliates of its General Partner closed the divestiture of our Hugoton net profits interest located in Texas County, Oklahoma and Stevens County, Kansas. This divestiture to a third party included operated working interests and related properties, our field office and our gathering system and related assets. The Partnership's share of proceeds from the transaction was $5.2 million, net of transaction costs.

On June 30, 2021, pursuant to a non-taxable contribution and exchange agreement with JSFM, LLC, a Wyoming limited liability company ("JSFM"), the Partnership acquired overriding royalty interests in the Bakken Trend totaling approximately 6,400 net royalty acres located in Dunn, McKenzie, McLean and Mountrail Counties, North Dakota in exchange for 725,000 common units representing limited partnership interests in the Partnership issued pursuant to the Partnership's registration statement on Form S-4.

On December 31, 2021, pursuant to a non-taxable contribution and exchange agreement with Gemini 5 Thirty, LP, a Texas limited partnership ("Gemini"), the Partnership acquired mineral and royalty interests representing approximately 4,600 net royalty acres located in 27 counties across New Mexico, Oklahoma, Texas and Wyoming in exchange for 1,580,000 common units representing limited partnership interests in the Partnership issued pursuant to the Partnership's registration statement on Form S-4.

Our business may be described as the acquisition, ownership and administration of Royalty Properties and NPI. The NPI represents a net profits overriding royalty interest burdening various properties owned by the Operating Partnership. We receive monthly payments equaling 96.97% of the net profits realized by the Operating Partnership from these properties in the preceding month. The Royalty Properties consist of producing and nonproducing mineral, royalty, overriding royalty, net profits, and leasehold interests located in 582 counties and parishes in 26 states ("Royalty Properties").

Our partnership agreement requires that we distribute quarterly an amount equal to all funds that we receive from the Royalty Properties and the NPI (other than cash proceeds received by the Partnership from a public or private offering of securities of the Partnership) less certain expenses and reasonable reserves.

Our partnership agreement allows us to grow by acquiring additional oil and natural gas properties, subject to the limitations described below. The approval of the holders of a majority of our outstanding common units is required for our General Partner to cause us to acquire or obtain any oil and natural gas property interest, unless the acquisition is complementary to our business and is made either:

- in exchange for our limited partner interests, including common units, not exceeding 40% of the common units outstanding after issuance; or
- in exchange for cash proceeds of any public or private offer and sale of limited partner interests, including common units, or options, rights, warrants or appreciation rights relating to the limited partner interests, including common units; or
- in exchange for other cash from our operations, if the aggregate cost of any acquisitions made for cash during the twelve-month period ending on the first to occur of the execution of a definitive agreement for the acquisition or its consummation is no more than 10% of our aggregate cash distributions for the four most recent fiscal quarters.

Unless otherwise approved by the holders of a majority of our common units, in the event that we acquire properties for a combination of cash and limited partner interests, including common units, (i) the cash component of the acquisition consideration must be equal to or less than 5% of the aggregate cash distributions made by the Partnership for the four most recent quarters and (ii) the amount of limited partnership interests, including common units, to be issued in such acquisition, after giving effect to such issuance, shall not exceed 10% of the common units outstanding.

Credit Facilities and Financing Plans

We do not have a credit facility in place, nor do we anticipate doing so. We do not anticipate incurring any debt, other than trade debt incurred in the ordinary course of our business. Our partnership agreement prohibits us from incurring indebtedness, other than trade payables, (i) in excess of $50,000 in the aggregate at any given time; or (ii) which would constitute "acquisition indebtedness" (as defined in Section 514 of the Internal Revenue Code of 1986, as amended), in order to avoid unrelated business taxable income for federal income tax purposes. We may finance any growth of our business through acquisitions of oil and natural gas properties by issuing additional limited partnership interests or with cash, subject to the limits described above and in our partnership agreement.

Under our partnership agreement, we may also finance our growth through the issuance of additional partnership securities, including options, rights, warrants and appreciation rights with respect to partnership securities from time to time in exchange for the consideration and on the terms and conditions established by our General Partner in its sole discretion. However, we may not issue limited partnership interests that would represent over 40% of the outstanding limited partnership interests immediately after giving effect to such issuance or that would have greater rights or powers than our common units without the approval of the holders of a majority of our outstanding common units. Except in connection with qualifying acquisitions, we do not currently anticipate issuing additional partnership securities. We have effective registration statements registering an aggregate of 30,000,000 common units that may be offered and issued by the Partnership from time to time in connection with asset acquisitions or other business combination transactions. At present, 27,695,000 units remain available under the Partnership’s registration statements.

Regulation

Many aspects of the production, pricing and marketing of oil and natural gas are regulated by federal and state agencies. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, which frequently increases the regulatory burden on affected members of the industry.

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes:

- permits for the drilling of wells;
- bonding requirements in order to drill or operate wells;
- the location and number of wells;
- the method of drilling and completing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandonment of wells;
- numerous federal and state safety requirements;
- environmental requirements;
- property taxes and severance taxes; and
- specific state and federal income tax provisions.

Oil and natural gas operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units and the density of wells that may be drilled and the unitization or pooling of oil and natural gas properties. In addition, state conservation laws establish a maximum allowable production from oil and natural gas wells. These state laws also generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. These regulations can limit the amount of oil and natural gas that the operators of our properties can produce.

The transportation of oil and natural gas after sale by operators of our properties is sometimes subject to regulation by state authorities. The interstate transportation of oil and natural gas is subject to federal governmental regulation, including regulation of tariffs and various other matters, primarily by the Federal Energy Regulatory Commission.

Significant Customers

If we were to lose a significant customer, such loss could impact revenue. The loss of any single customer is mitigated by our diversified customer base and individually insignificant properties, and we do not believe that the loss of any single customer would have a long-term material adverse effect on our financial position or the results of operations. Royalty revenues from properties operated by Pioneer Natural Resources Company represented approximately 13% of total operating revenues for the year ended December 31, 2021.

Customer and Commodity Price Risks

The pricing of oil and natural gas sales is primarily determined by supply and demand in the global marketplace and can fluctuate considerably. As a royalty owner and non-operator, we have extremely limited access to timely information and involvement and no operational control over the volumes of oil and natural gas produced and sold or the terms and conditions on which such volumes are marketed and sold.

Our profitability is affected by oil and natural gas market prices. Oil and natural gas market prices have fluctuated significantly in recent years in response to changes in the supply and demand for oil and natural gas in the market, along with domestic and international political and economic conditions.

In January 2020, the World Health Organization ("WHO") announced a global health emergency because of a new strain of coronavirus ("COVID-19") and the significant risks to the international community and economies as the virus spreads globally beyond its point of origin. In March 2020, the WHO classified COVID-19 as a pandemic, based on the rapid increase in exposure globally, and thereafter, COVID-19 continued to spread throughout the U.S. and worldwide. In addition, in early March 2020, oil prices dropped sharply and continued to decline, briefly reaching negative levels, as a result of multiple factors affecting the supply and demand in global oil and natural gas markets, including (i) actions taken by OPEC members and other exporting nations impacting commodity price and production levels and (ii) a significant decrease in demand due to the COVID-19 pandemic. Additionally, multiple variants emerged in 2021 and became highly transmissible, which contributed to additional pricing and demand volatility during 2021 to date. However, certain restrictions on conducting business that were implemented in response to the COVID-19 pandemic have been lifted as improved treatments and vaccinations became available for COVID-19 since late 2020. As a result, in addition to other changing market conditions, oil and natural gas market prices have improved in response to the increase in demand. Commodity prices have historically been volatile and we cannot predict events which may lead to future fluctuations in these prices. However, additional actions may be required in response to the COVID-19 pandemic on a national, state and local level by governmental authorities, and such actions may further adversely affect general and local economic conditions (including further closures of businesses), particularly if the 2021 resurgence and spread of the COVID-19 pandemic continues. The COVID-19 pandemic continues to be dynamic and evolving, and its ultimate duration and effects remain uncertain.

Competition

The energy industry in which we compete is subject to intense competition among many companies, both larger and smaller than we are, many of which have financial and other resources greater than we have.

Business Opportunities Agreement

Pursuant to a business opportunities agreement among us, our General Partner, the general partner of our General Partner, and the owners of the general partner of our General Partner (the "GP Parties"), we have agreed that, except with the consent of our General Partner, which it may withhold in its sole discretion, we will not engage in any business not permitted by our partnership agreement, and we will have no interest or expectancy in any business opportunity that does not consist exclusively of the oil and natural gas business within a designated area that includes portions of Texas County, Oklahoma and Stevens County, Kansas. All opportunities that are outside the designated area or are not oil and natural gas business activities are called renounced opportunities.

The parties also have agreed that, as long as the activities of the General Partner, the GP Parties and their affiliates or manager designees are conducted in accordance with specified standards, or are renounced opportunities:

- our General Partner, the GP Parties and their affiliates or the manager designees will not be prohibited from engaging in the oil and natural gas business or any other business, even if such activity is in direct or indirect competition with our business activities;
- affiliates of our General Partner, the GP Parties and their affiliates and the manager designees will not have to offer us any business opportunity;
- we will have no interest or expectancy in any business opportunity pursued by affiliates of our General Partner, the GP Parties or their affiliates and the manager designees; and
- we waive any claim that any business opportunity pursued by our General Partner, the GP Parties or their affiliates and the manager designees constitutes a corporate opportunity that should have been presented to us.

The standards specified in the business opportunities agreement generally provide that the GP Parties and their affiliates and manager designees must conduct their business through the use of their own personnel and assets and not with the use of any personnel or assets of us, our General Partner or Operating Partnership. A manager designee or personnel of a company in which any affiliate of our General Partner or any GP Party or their affiliates has an interest or in which a manager designee is an owner, director, manager, partner or employee (except for our General Partner and its general partner and their subsidiaries) is not allowed to usurp a business opportunity solely for his or her personal benefit, as opposed to pursuing, for the benefit of the separate party an opportunity in accordance with the specified standards.

In certain circumstances, if a GP Party or any subsidiary thereof, any officer of the general partner of our General Partner or any of their subsidiaries, or a manager of the general partner of our General Partner that is an affiliate of a GP Party signs a binding agreement to purchase oil and natural gas interests, excluding oil and natural gas working interests, then such party must notify us prior to the consummation of the transactions so that we may determine whether to pursue the purchase of the oil and natural gas interests directly from the seller. If we do not pursue the purchase of the oil and natural gas interests or fail to respond to the purchasing party's notice within the provided time, the opportunity will also be considered a renounced opportunity.

In the event any GP Party or one of their subsidiaries acquires an oil and natural gas interest, including oil and natural gas working interests, in the designated area, it will offer to sell these interests to us within one month of completing the acquisition. This obligation also applies to any package of oil and natural gas interests, including oil and natural gas working interests, if at least 20% of the net acreage of the package is within the designated area; however, this obligation does not apply to interests purchased in a transaction in which the procedures described above were applied and followed by the applicable affiliate.

Operating Hazards and Uninsured Risks

Our operations do not directly involve the operational risks and uncertainties associated with drilling for, and the production and transportation of, oil and natural gas. However, we may be indirectly affected by the operational risks and uncertainties faced by the operators of our properties, whose operations may be materially curtailed, delayed or canceled as a result of numerous factors, including:

- the presence of unanticipated pressure or irregularities in formations;
- accidents;
- title problems;
- weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the delivery of equipment.

Also, the ability of the operators of our properties to market oil and natural gas production depends on numerous factors, many of which are beyond their control, including:

- capacity and availability of oil and natural gas systems and pipelines;
- effect of federal and state production and transportation regulations;
- changes in supply and demand for oil and natural gas; and
- creditworthiness of the purchasers of oil and natural gas.

The occurrence of an operational risk or uncertainty that materially impacts the operations of the operators of our properties could have a material adverse effect on the amount that we receive in connection with our interests in production from our properties, which could have a material adverse effect on our financial condition or result of operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of the risks to which our business exposes us. While we believe that we are reasonably insured against these risks, the occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations.

Employees

As of February 24, 2022, the Operating Partnership had 24 full-time employees in our Dallas, Texas corporate office. Due to the ongoing COVID-19 pandemic, we have a rotational work from home program in place. The health and safety of our employees is a high priority. We have added safety measures and protocols in our office to enhance employee and visitor protection against COVID-19.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Our cash distributions are highly dependent on oil and natural gas prices, which have historically been very volatile.

Our quarterly cash distributions depend significantly on the prices realized from the sale of oil and, in particular, natural gas. Historically, the markets for oil and natural gas have been volatile and may continue to be volatile in the future. Various factors that are beyond our control will affect prices of oil and natural gas, such as:

- the worldwide and domestic supplies of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and others to agree to and maintain oil prices and production controls;
- political instability or armed conflict in oil-producing regions;
- the price and level of foreign imports;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- weather conditions;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Lower oil and natural gas prices may reduce the amount of oil and natural gas that is economic to produce and may reduce our revenues and operating income. The volatility of oil and natural gas prices reduces the accuracy of estimates of future cash distributions to unitholders.

We do not control operations and development of the Royalty Properties or the properties underlying the NPIs that the Operating Partnership does not operate, which could impact the amount of our cash distributions.

As the owner of a fractional undivided mineral or royalty interest, we do not control the development of the Royalty or NPI properties or the volumes of oil and natural gas produced from them, and our ability to influence development of nonproducing properties is severely limited. Also, since one of our stated business objectives is to avoid the generation of unrelated business taxable income, we are prohibited from participation in the development of our properties as a working interest or other expense-bearing owner. The decision to explore or develop these properties, including infill drilling, exploration of horizons deeper or shallower than the currently producing intervals, and application of enhanced recovery techniques will be made by the operator and other working interest owners of each property (including our lessees) and may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations and general industry and economic conditions.

Our unitholders are not able to influence or control the operation or future development of the properties underlying the NPIs. The Operating Partnership is unable to influence the operations or future development of properties that it does not operate. The current operators of the properties underlying the NPIs are under no obligation to continue operating the underlying properties. Our unitholders do not have the right to replace an operator.

Our lease bonus revenue depends in significant part on the actions of third parties, which are outside of our control.

Significant portions of the Royalty Properties are unleased mineral interests. With limited exceptions, we have the right to grant leases of these interests to third parties. We anticipate receiving cash payments as bonus consideration for granting these leases in most instances. Our ability to influence third parties' decisions to become our lessees with respect to these nonproducing properties is severely limited, and those decisions may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations, and general industry and economic conditions.

The Operating Partnership may transfer or abandon properties that are subject to the NPIs.

Our General Partner, through the Operating Partnership, may at any time transfer all or part of the properties underlying the NPIs. Our unitholders are not entitled to vote on any transfer; however, any such transfer must also simultaneously include the NPIs at a corresponding price.

The Operating Partnership or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the NPIs relating to the abandoned well.

Cash distributions are affected by production and other costs, most of which are outside of our control.

The cash available for distribution that comes from our royalty and mineral interests, including the NPIs, is directly affected by increases in production costs and other costs. Most of these costs are outside of our control, including costs of regulatory compliance and severance and other similar taxes. Other expenditures are dictated by business necessity, such as drilling additional wells in response to the drilling activity of others.

Our oil and natural gas reserves and the underlying properties are depleting assets, and there are limitations on our ability to replace them.

Our revenues and distributions depend in large part on the quantity of oil and natural gas produced from properties in which we hold an interest. Over time, all of our producing oil and natural gas properties will experience declines in production due to depletion of their oil and natural gas reservoirs, with the rates of decline varying by property. Replacement of reserves to maintain production levels requires maintenance, development or exploration projects on existing properties, or the acquisition of additional properties.

The timing and size of maintenance, development or exploration projects will depend on the market prices of oil and natural gas and on other factors beyond our control. All of the decisions regarding implementation of such projects, including drilling or exploration on any unleased and undeveloped acreage, will be made by third parties.

Our ability to increase reserves through future acquisitions is limited by restrictions on our use of operating cash and limited partnership interests for acquisitions and by our General Partner's obligation to use all reasonable efforts such as NPIs to avoid unrelated business taxable income. In addition, the ability of affiliates of our General Partner to pursue business opportunities for their own accounts without tendering them to us in certain circumstances may reduce the acquisitions presented to us for consideration.

Acreage must be drilled before lease expiration, generally within three years, in order to hold the acreage by production. Our operators' failure to drill sufficient wells to hold acreage may result in the deferral of prospective drilling opportunities. In addition, our ORRIs may terminate if the underlying acreage is not drilled before the expiration of the applicable lease or if the lease otherwise terminates.

Leases on oil and natural gas properties typically have a term of three years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. In addition, even if production or drilling is established during such primary term, if production or drilling ceases on the leased property, the lease typically terminates, subject to certain exceptions.

Any reduction in our operators' drilling programs, either through a reduction in capital expenditures or the unavailability of equipment, services, or supplies, could result in the expiration of existing leases. If the lease governing any of our mineral interests expires or terminates, all development rights typically revert back to us, and we may seek new lessees to explore and develop such mineral interests or in some states remain unleased. If the lease underlying any of our ORRIs expires or terminates, our ORRIs that are derived from such lease will also terminate. Any such expirations or terminations of our leases or our ORRIs could materially and adversely affect our financial condition, results of operations and cash flow.

If our operators suspend our right to receive royalty payments due to title or other issues, our business, financial condition, results of operations and cash flows may be adversely affected.

Our business depends, in part, on acquisitions which contribute to the growth of our reserves, production and cash generated from operations. In connection with these acquisitions, we are conveyed record title to mineral and royalty interests. Due to such changes in ownership of mineral interests, the operator of the underlying property has the right, at such operator's discretion, to investigate and verify the title and ownership of mineral and royalty interests with respect to the properties it operates. If any title or ownership issues are not resolved to its reasonable satisfaction in accordance with customary industry standards, the operator has the right to suspend payment of the related royalty. If an operator of our properties is not satisfied with the documentation we provide to validate our ownership, such operator may suspend our royalty payment until such issues are resolved, at which time we would receive the full royalty payment which we would have otherwise received if not for the payment being suspended, without interest. Certain of our operators impose burdensome documentation requirements for title transfer and may keep royalty payments in suspense for significant periods of time. During the time that an operator puts our assets in pay suspense, we would not receive the applicable mineral or royalty payment owed to us from sales of the underlying oil or natural gas related to such mineral or royalty interest. If a significant amount of our royalty interests are placed in suspense, our results of operations and cash flow may be materially affected.

Title to the properties in which we have an interest may be impaired by title defects.

In our discretion, we may elect not to incur the expense of retaining lawyers to examine the title to our royalty and mineral interests. In such cases, we would rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before acquiring a specific royalty or mineral interest. The existence of a material title deficiency can have a significant adverse effect on the value of an interest and can further materially adversely affect our results of operations, financial condition and cash flows.

We may experience delays in received royalty payments and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

We may experience delays in receiving royalty payments from our operators, including as a result of delayed division orders received by our operators. Typically, the failure of an operator to make royalty payments to which we are entitled, gives us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we cannot guarantee finding a suitable replacement operator in such a circumstance and if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a bankruptcy proceeding under Title 11 of the United States Code (the "Bankruptcy Code"), in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise at risk. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have an extended period of time to decide whether to ultimately reject or assume the lease, which could significantly delay or prevent the execution of a new lease or the assignment of the existing lease to a replacement operator. In the event that an operator rejects the lease, our ability to collect amounts owed to us would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, there is no guarantee that such replacement operator will achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

We do not currently plan to enter into hedging arrangements with respect to the oil and natural gas production from our properties, and we will be exposed to the impact of decreases in the price of oil and natural gas.

We do not currently plan to enter into hedging arrangements to establish, in advance, a price for the sale of the oil and natural gas produced from our properties. As a result, although we may realize the benefit of any short-term increase in the price of oil and natural gas, we will not be protected against decreases in the price of oil and natural gas or prolonged periods of low commodity prices, which could materially adversely affect our business, results of operation and cash available for distribution. If we enter into hedging arrangements in the future, it may limit our ability to realize the benefit of rising prices and may result in hedging losses.

Competition in the oil and natural gas industry is intense, which may adversely affect our and our operators' ability to succeed.

The oil and natural gas industry is intensely competitive, and the operators of our properties compete with other companies that may have greater resources or greater access to capital. Many of these companies explore for and produce oil and natural gas, carry on midstream and refining operations, and market petroleum and other products on a regional, national or worldwide basis. In addition, these companies may have a greater ability to continue exploration activities during periods when market prices of oil and natural gas are low. Our operators' larger competitors may be able to better address the burden of present and future federal, state, local and other laws and regulations more easily than our operators can, which could adversely affect our operators' competitive position. Our operators may have access to fewer financial and human resources than many companies in our operators' industry and may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. Furthermore, the oil and natural gas industry has experienced recent consolidation amongst some operators, which has resulted in certain instances of combined companies with larger resources. Such combined companies may compete against our operators or, in the case of consolidation amongst our operators, may choose to focus their operations on areas outside of our properties. In addition, we cannot guarantee our ability to acquire additional properties and to discover reserves in the future as this will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Drilling activities on our properties may not be productive, which could have an adverse effect on future results of operations and financial condition.

The Operating Partnership may participate in drilling activities in limited circumstances on the properties underlying the NPIs, and third parties may undertake drilling activities on our properties. Any increases in our reserves will come from such drilling activities or from acquisitions.

Drilling involves a wide variety of risks, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be delayed or canceled as a result of a variety of factors, including:

- pressure or irregularities in formations;
- equipment failures or accidents;
- unexpected drilling conditions;
- shortages or delays in the delivery of equipment;
- adverse weather conditions; and
- disputes with drill-site owners.

Future drilling activities on our properties may not be successful. If these activities are unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. In addition, under the terms of the NPIs, the costs of unsuccessful future drilling on the working interest properties that are subject to the NPIs will reduce amounts payable to us under the NPIs by 96.97% of these costs.

Our ability to identify and capitalize on acquisitions is limited by contractual provisions and substantial competition.

Our partnership agreement limits our ability to acquire oil and natural gas properties in the future, especially for consideration other than our limited partnership interests or cash proceeds of a securities offering. Because of the limitations on our use of operating cash for acquisitions and on our ability to accumulate operating cash for acquisition purposes, we may be required to attempt to effect acquisitions by first selling our securities to raise cash or by issuing our limited partnership interests. However, we may be unable to sell our securities in sufficient quantities and for sufficient consideration to provide adequate consideration to fund an acquisition, and sellers of properties we would like to acquire may be unwilling to take our limited partnership interests in exchange for properties.

Our partnership agreement obligates our General Partner to use all reasonable efforts to avoid generating unrelated business taxable income. Accordingly, to acquire working interests we would have to arrange for them to be converted into overriding royalty interests, net profits interests, or another type of interest that does not generate unrelated business taxable income. Third parties may be less likely to deal with us than with a purchaser to which such a condition would not apply. These restrictions could prevent us from pursuing or completing business opportunities that might benefit us and our unitholders, particularly unitholders who are not tax-exempt investors.

The duty of affiliates of our General Partner to present acquisition opportunities to our Partnership is limited, pursuant to the terms of the business opportunities agreement. Accordingly, business opportunities that could potentially be pursued by us might not necessarily come to our attention, which could limit our ability to pursue a business strategy of acquiring oil and natural gas properties.

We compete with other companies and producers for acquisitions of oil and natural gas interests. Many of these competitors have substantially greater financial and other resources than we do.

Any future acquisitions will involve risks that could adversely affect our business, which our unitholders generally will not have the opportunity to evaluate.

Our current strategy contemplates that we may grow through acquisitions and development of our undeveloped property. We expect to participate in discussions relating to potential acquisition and investment opportunities. If we consummate any additional acquisitions and investments, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in connection with the acquisition, unless the terms of the acquisition require approval of our unitholders. Additionally, our unitholders will bear 100% of the dilution from issuing new common units while receiving essentially 96% of the benefit as 4% of the benefit goes to our General Partner.

Acquisitions and business expansions involve numerous risks, including assimilation difficulties, unfamiliarity with new assets or new geographic areas and the diversion of management's attention from other business concerns. In addition, the success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attributable to reserves and to assess possible environmental liabilities. Our review and analysis of properties prior to any acquisition will be subject to uncertainties and, consistent with industry practice, may be limited in scope. We may not be able to successfully integrate any oil and natural gas properties that we acquire into our operations, or we may not achieve desired profitability objectives.

A natural disaster or catastrophe could damage pipelines, gathering systems and other facilities that service our properties, which could substantially limit our operations and adversely affect our cash flow.

If gathering systems, pipelines or other facilities that serve our properties are damaged by any natural disaster, accident, catastrophe or other event, our income could be significantly interrupted. Any event that interrupts the production, gathering or transportation of our oil and natural gas, or which causes us to share in significant expenditures not covered by insurance, could adversely impact the market price of our limited partnership units and the amount of cash available for distribution to our unitholders. We do not carry business interruption insurance.

A significant portion of the properties subject to the NPIs are geographically concentrated, which could cause net proceeds payable under the NPIs to be impacted by regional events.

A significant portion of the properties subject to the NPIs are properties located in the Bakken region and Permian Basin. Because of this geographic concentration, any regional events, including natural disasters that increase costs, reduce availability of equipment, services, or supplies, reduce demand or limit production may impact the net proceeds payable under the NPIs more than if the properties were more geographically diversified.

Under the terms of the NPIs, much of the economic risk of the underlying properties is passed along to us.

Under the terms of the NPIs, virtually all costs that may be incurred in connection with the properties, including overhead costs that are not subject to an annual reimbursement limit, are deducted as production costs or excess production costs in determining amounts payable to us. Therefore, to the extent of the revenues from the burdened properties, we bear 96.97% of the costs of the working interest properties. If costs exceed revenues, we do not receive any payments under the NPIs. However, except as described below, we are not required to pay any excess costs.

The terms of the NPIs provide for excess costs that cannot be charged currently because they exceed current revenues to be accumulated and charged in future periods, which could result in us not receiving any payments under the NPIs until all prior uncharged costs have been recovered by the Operating Partnership.

Our cash flow is subject to operating hazards and unforeseen interruptions for which we may not be fully insured.

Neither we nor the Operating Partnership are fully insured against certain risks, either because such full insurance is not available or because of high premium costs. Operations that affect the properties are subject to all of the risks normally incident to the oil and natural gas business, including blowouts, cratering, explosions, and pollution and other environmental damage, any of which could result in substantial decreases in the cash flow from our royalty interests and other interests due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Any uninsured costs relating to the properties underlying the NPIs will be deducted as a production cost in calculating the net proceeds payable to us.

Governmental policies, laws and regulations could have an adverse impact on our business and cash distributions.

Our business and the properties in which we hold interests are subject to federal, tribal, state and local laws and regulations relating to the oil and natural gas industry as well as regulations relating to environmental, health, and safety matters. These laws and regulations can have a significant impact on production and costs of production. For example, in Oklahoma, where properties that are subject to the NPIs are located, regulators have the ability, directly or indirectly, to limit production from those properties, and such limitations or changes in those limitations could negatively impact us in the future.

Cyber incidents or attacks targeting systems and infrastructure used by the oil and natural gas industry may adversely impact our operations, and if we are unable to obtain and maintain adequate protection of our data, our business may be adversely impacted.

We and our operators increasingly rely on information technology systems to operate our respective businesses, and the oil and natural gas industry depends on digital technologies in exploration, development, production, and processing activities. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. Our technologies, systems, networks, and those of the operators of our properties, vendors, suppliers, and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of business activities. In addition, certain cyber incidents, such as surveillance, may remain undetected for some period of time. While we utilize various procedures and controls to mitigate exposure to such risk, cyber incidents and attacks are evolving and unpredictable. Our information technology systems and any insurance coverage for protecting against cybersecurity risks may not be sufficient. As cyber security threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. It is possible that our business, finances, systems and assets could be compromised in a cyber attack.

The Partnership may be adversely affected by price volatility in the oil and natural gas markets.

Historically, there has been price volatility in the oil and natural gas markets, which have been impacted by a number of factors, including actions by oil producing nations. For example, after OPEC and a group of oil producing nations led by Russia failed in March 2020 to agree on oil production cuts, Saudi Arabia announced that it would cut oil prices and increase production, leading to a sharp decline in oil and natural gas prices. While OPEC, Russia and other oil producing countries reached an agreement in April 2020 to reduce production levels, and U.S. production declined, oil prices remained lower than in previous years on account of an oversupply of oil and natural gas, with a simultaneous decrease in demand as a result of the impact of COVID-19 on the global economy. Thereafter, in 2021, oil and natural gas prices significantly rebounded. Although we continue to see sustained improvements in pricing, on account of a number of factors, including unusually high pricing due to extreme winter weather in early 2021, the oil and natural gas markets remain subject to price volatility, which may have a material adverse effect on our cash distributions in periods of lower prices. During periods of substantial declines in prices, such as in 2020, oil and natural gas operators on our properties may suspend drilling programs, which would impact our revenues and operating income. In the event that any wells on our properties are shut-in, restarting wells may require significant costs from our operators, and we cannot guarantee that they would be able to restart at the same level. Moreover, due to the extremely volatile market conditions, we are unable to predict the degree or duration of any adverse impact on our operations and financial condition and other risks in our industry may be enhanced by such conditions.

Regulatory and Environmental Risk Factors

Environmental costs and liabilities and changing environmental regulation could affect our cash flow.

As with other companies engaged in the ownership and production of oil and natural gas, we always have possible risk of exposure to environmental costs and liabilities because of the costs associated with environmental compliance or remediation. The properties in which we hold interests are subject to extensive federal, state, tribal and local regulatory requirements relating to environmental affairs, health and safety and waste management. Governmental authorities have the power to enforce compliance with applicable regulations and permits, which could increase production costs on our properties and affect their cash flow. Third parties may also have the right to pursue legal actions to enforce compliance. Because we do not directly operate our properties, our direct liability under environmental laws is limited. It is likely, however, that expenditures in connection with environmental matters, individually or as part of normal capital expenditure programs, will affect the net cash flow from our properties. Future environmental law developments, such as stricter laws, regulations or enforcement policies, could significantly increase the costs of production from our properties and reduce our cash flow.

The following is a summary of some of the existing environmental laws, rules and regulations that apply to oil and natural gas operations, and that may indirectly affect our cash flow.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state statutes impose strict liability (i.e., no showing of "fault" is required), and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. The term "hazardous substance" is specifically defined to exclude petroleum, including crude oil and any fraction thereof, natural gas and natural gas liquids. Despite this exclusion, certain materials that are commonly used in connection with oil and natural gas operations are considered to be hazardous substances under CERCLA. Responsible persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed of or arranged for the disposal of a hazardous substance released at the site, regardless of whether the disposal of hazardous substances was lawful at the time of the disposal. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of investigating releases of hazardous substances, cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The operators of our properties may be responsible under CERCLA for all or part of these costs. Although we are not an operator, our ownership of royalty interests could cause us to be responsible for all or part of such costs to the extent that CERCLA imposes such responsibilities on such parties as "owners."

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced water and many other wastes associated with the exploration, development and production of oil or natural gas are currently excluded from regulation under RCRA's hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes could be classified as hazardous wastes in the future. In addition, exploration and production wastes are regulated under state laws analogous to RCRA. Many of our properties have produced oil and/or natural gas for many years. We have no knowledge of current and prior operators' procedures with respect to the disposal of oil and natural gas wastes. Hydrocarbons or other solid or hazardous wastes may have been released on or under our properties by the operators or prior operators. Our properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws, and removal or remediation of such materials could be required by a governmental authority.

The Federal Clean Air Act ("CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and other requirements, such as emissions controls. Existing laws and regulations and possible future laws and regulations may require our operators to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions and may impose stringent air permit requirements or mandate the use of specific equipment or technologies to control emissions. The U.S. Environmental Protection Agency ("EPA") continues to develop New Source Performance standards for oil and natural gas facilities. Most recently, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, on August 13, 2020, in response to an executive order by former President Trump, the EPA amended the New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. On June 30, 2021, President Biden signed into law a joint resolution of Congress disapproving the 2020 amendments, with the exception of some technical changes, thereby reinstating the prior standards. The EPA expects owners and operators of regulated sources to take "immediate steps" to comply with these standards. Additionally, on November 15, 2021, the EPA published a proposed rule that would expand and strengthen emission reduction requirements for both new and existing sources in the oil and natural gas industry by requiring increased monitoring of fugitive emissions, imposing new requirements for pneumatic controllers and tank batteries, and prohibiting venting of natural gas in certain situations. Federal changes will affect state air permitting programs in states that administer the federal CAA under a delegation of authority, including states in which we have operations.

The Federal Water Pollution Control Act (the "Clean Water Act" or "CWA") and analogous state laws impose restrictions and strict controls on the discharge of pollutants and fill material, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers ("USACOE"). On June 29, 2015, EPA and the USACOE jointly promulgated a final rule redefining the scope of "Waters of the United States" ("WOTUS"), which would have made additional waters subject to the jurisdiction of the Clean Water Act. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 WOTUS rule, and then, on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rule, and significantly reducing the waters subject to federal regulation under the CWA. On August 30, 2021, a federal court struck down the replacement rule and, on December 7, 2021, the EPA and the Corps published a proposed rule that would put back into place the pre-2015 definition of "waters of the United States," updated to reflect Supreme Court decisions, while the agencies continue to consult with stakeholders on future regulatory actions. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the CWA. To the extent the rules expand the range of properties subject to the CWA's jurisdiction, our operators could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which could cause delays in development and/or increase the cost of development and operation of those properties.

Spill prevention, control, and countermeasure ("SPCC") regulations promulgated under the Clean Water Act and later amended by the Oil Pollutions Act of 1990 impose obligations and liabilities related to the prevention of oil spills and damages resulting from such spills into or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities that store oil in more than threshold quantities, the release of which could reasonably be expected to reach jurisdictional waters, must develop, implement, and maintain SPCC Plans. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

Various federal laws, including the Endangered Species Act and the Migratory Bird Treaty Act, and analogous state laws, restrict activities that may adversely affect listed endangered or threatened species or their habitat. If endangered or threatened species are located on our properties, operations on those properties could be prohibited or delayed or expensive mitigation may be required. Also, the United States Fish and Wildlife Service ("USFWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access, development or operations (including prevent oil and natural gas exploration or production). Additionally, the designation of previously unprotected species in areas where we operate as endangered or threatened could result in the imposition of restrictions on our operators and consequently have a material adverse effect on our business.

Oil and natural gas operations are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes and their implementing regulations. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA, the general duty clause and Risk Management Planning regulations promulgated under section 112(r) of the CAA and similar state statutes may require disclosure of information about hazardous materials used, produced or otherwise managed during operation. These laws also require the development of risk management plans for certain facilities to prevent accidental releases of extremely hazardous substances and to minimize the consequences of such releases should they occur.

The potential adoption of federal and state hydraulic fracturing legislation or executive orders could delay or restrict development of our oil and natural gas properties.

Hydraulic fracturing is an important, common practice that is used to stimulate production of hydrocarbons from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act ("SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the SDWA. Future federal laws or regulations could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Such federal legislation or regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing.

In addition, on March 26, 2015, the Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. Also, on November 18, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and natural gas operations on federal and Indian lands. On March 28, 2017, former President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. State and environmental groups have challenged this rollback. Also, on September 28, 2018, the BLM published a final rule to revise the 2016 methane rule; however, a federal court struck down the scaled-back rule on July 15, 2020, and shortly thereafter, on October 8, 2020, another federal court struck down the 2016 methane rule. At this time, it is uncertain when, or if, the above rules will be implemented or if new requirements will be adopted. Each of these regulations, to the extent that they are reinstated or modified, may result in additional levels of regulation or complexity that could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase costs of compliance.

Additionally, certain states in which our properties are located, including Oklahoma, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, pursuant to legislation adopted by the State of Texas in June 2011, the Railroad Commission of Texas enacted a rule in December 2011, requiring public disclosure of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit well drilling in general and/or hydraulic fracturing in particular. In response to a 2014 ballot initiative by the voters of the City of Denton, Texas banning hydraulic fracturing, the Texas legislature enacted a statute preempting local government regulation of oil and natural gas activities, including hydraulic fracturing. In other states, however, local governments may retain the ability to directly or indirectly regulate hydraulic fracturing. State and local governments may also seek to regulate or recover costs of activities tangentially associated with hydraulic fracturing, such as increased truck traffic. In the event state, local, or municipal legal restrictions are adopted in areas where our properties are located, the cost of the operators of our oil and natural gas properties to comply with such requirements may be significant in nature, which may cause delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even preclude the operators from drilling wells.

Some states have become concerned about the connection between hydraulic fracturing-related activities, particularly the injection or disposal of produced water, and the increased occurrence of seismic activity, and they have adopted or are considering additional regulations regarding such activities. Changes in regulations or the inability to obtain permits for new disposal wells in the future may affect the ability of the operators of the Royalty Properties and the operators of the working interests and other properties underlying our NPIs to dispose of produced water and ultimately increase the cost of operation of the Royalty Properties and the working interests and other properties underlying our NPIs or delay production schedules. Certain state agencies, including those in Texas and Oklahoma, have implemented regulations authorizing the imposition of certain limitations on existing wells if seismic activity increases in the area of an injection well, including a temporary injection ban. For example, in Oklahoma, the Oklahoma Corporations Commission ("OCC") has implemented a variety of measures, including the adoption of the National Academy of Science's "traffic light system," pursuant to which the agency reviews new disposal well applications and may restrict operations at existing wells. Beginning in 2013, the OCC has ordered the reduction of disposal volumes into the Arbuckle formation. More recently, the OCC directed the shut in of a number of disposal wells due to increased earthquake activity in the Arbuckle formation and imposed further disposal well volume reductions in the Covington, Crescent, Enid, and Edmond areas. The Texas Railroad Commission has also implemented measures to assess the potential for seismic activity in the vicinity of disposal wells, and it has restricted and indefinitely suspended disposal well activities in some cases. Moreover, vigorous public debate over hydraulic fracturing and shale gas production continues and has resulted in delays of well permits in some areas.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies have also evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for our operators to perform fracturing and increase their costs of compliance and doing business.

The adoption of climate change legislation or regulations could result in increased operating costs and reduced demand for the oil and natural gas production from our properties.

Congress has, from time to time, considered legislation to reduce greenhouse gas ("GHG") emissions, such as the Build Back Better Act approved by the U.S. House of Representatives in November 2021. To date, Congress has not passed a bill specifically addressing GHG regulation. Almost half of the states, however, have taken measures to reduce GHG emissions primarily though the development of GHG emission inventories and/or regional GHG cap and trade programs. The cap and trade programs require major sources of emissions or major fuel producers to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Many states also have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources. In addition, states have imposed increasingly stringent requirements related to the venting or flaring of natural gas during oil and natural gas operations.

Responding to scientific studies that have suggested that emissions of GHGs, including gases associated with the oil and natural gas sector such as carbon dioxide, methane, and nitrous oxide among others, may be contributing to global warming and other environmental effects, the EPA has begun to adopt regulations to report and reduce emissions of greenhouse gases. Any such regulations may have the potential to affect our business, customers or the energy sector generally.

In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change ("UNFCCC"). The U.S. was among approximately 195 nations that signed an international accord in December 2015, the so called Paris Agreement, which became effective on November 4, 2016, with the objective of limiting greenhouse gas emissions. Although the United States withdrew from the Paris Agreement effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which went into effect on February 19, 2021. On April 21, 2021, the United States announced that it was setting an economy-wide target of reducing its greenhouse gas emissions by 50-52 percent below 2005 levels in 2030. In November 2021, in connection with Glasgow Climate Pact, the United States and other world leaders made further commitments to reduce greenhouse gas emissions, including reducing global methane emissions by at least 30% by 2030. Although these international commitments are not directly binding on companies, additional GHG reduction regulatory requirements may be issued in an effort to help meet the U.S. commitments under the Paris Agreement.

Although it is not possible at this time to predict whether or when Congress may act on climate change legislation, or whether EPA may promulgate additional regulation of GHGs from the oil and natural gas industry, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require oil and natural gas operators that develop our properties to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas produced from our properties.

It should also be noted that, recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. In addition, spurred by increasing concerns regarding climate change, the oil and natural gas industry faces growing demand for corporate transparency and a demonstrated commitment to sustainability goals. Environmental, social, and governance ("ESG") goals and programs, which typically include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing focus of investors and shareholders across the industry. While reporting on ESG metrics remains voluntary, access to capital and investors is likely to favor companies with robust ESG programs in place. Ultimately, these initiatives could make it more difficult to secure funding for exploration and production activities.

Finally, climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our operators' activities and increase their costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

The new Biden administration, acting through the executive branch or in coordination with Congress, could enact rules and regulations that reduce our revenues and cash distributions in the future or increase operating costs for the oil and natural gas production from our properties.

President Biden has indicated that he is supportive of various programs and initiatives designed to, among other things, curtail climate change, control the release of methane from new and existing oil and natural gas operations, and decarbonize electric generation and the transportation sector. During his first month in office, in January 2021, President Biden signed an Executive Order temporarily suspending oil and natural gas permitting on federal lands and offshore waters. While the moratorium was lifted in June 2021, President Biden has indicated that his administration is likely to pursue additional measures to limit GHG emissions from oil and natural gas operations. It remains unclear, however, what specific actions President Biden will take and what support he will have for any potential legislative changes from Congress. Further, it is uncertain to what extent any new environmental laws or regulations, or any repeal of existing environmental laws or regulations, may affect our business or operations. However, any of these actions could adversely affect our revenues and cash distributions by requiring oil and natural gas operators that develop our properties to incur increased operating costs and could have an adverse effect on the amount of and demand for the oil and natural gas produced from our properties.

Our oil and natural gas reserve data and future net revenue estimates are uncertain.

Estimates of proved reserves and related future net revenues are projections based on engineering data and reports of independent consulting petroleum engineers hired for that purpose. The process of estimating reserves requires substantial judgment, resulting in imprecise determinations. Different reserve engineers may make different estimates of reserve quantities and related revenue based on the same data. Therefore, those estimates should not be construed as being accurate estimates of the current market value of our proved reserves. If these estimates prove to be inaccurate, our business may be adversely affected by lower revenues. We are affected by changes in oil and natural gas prices. Oil prices and natural gas prices may experience inverse price changes.

The outcome of pending litigation related to the Dakota Access Pipeline and any related executive orders could have a material adverse effect on our revenue and cash distributions.

In connection with ongoing litigation initiated in February 2017 by the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe contesting the validity of the process used by the USACOE to permit the Dakota Access Pipeline, on July 6, 2020, the United States District Court for the District of Columbia (the "Court") issued an order vacating the USACOE's easement for the Dakota Access Pipeline and requiring that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the USACOE appealed the decision. On July 14, 2020, the Court of Appeals granted a temporary administrative stay, and on January 26, 2021, the Court of Appeals affirmed that part of the lower court decision vacating the USACOE's easement while it prepares a new environmental impact statement, but reversed the lower court's order to shut down the pipeline. Since then, both the Biden Administration and the Court have declined to shut down the pipeline, and on June 22, 2021, the Court dismissed the subject lawsuit. The Court noted, however, that future challenges were possible depending on the outcome of the ongoing environmental study, which is expected to be completed in late 2022. Accordingly, the continued operation of Dakota Access Pipeline in the future is uncertain. While this litigation does not directly impact our operations, we derive a significant amount of revenue from the Royalty Properties and NPIs we hold in the Bakken region, the region for which the Dakota Access Pipeline is intended to be a key pipeline. The outcome of this litigation may have a material adverse affect on our Royalty and NPI revenues derived from the Bakken region based on the timing of future development of wells on, or production of oil and natural gas from, or the method and cost of transportation related to the production on the properties. We have no control over the operation of such properties.

Risks Inherent In An Investment In Our Common Units

Cost reimbursement due our General Partner may be substantial and reduce our cash available to distribute to our unitholders.

Prior to making any distribution on the common units, we reimburse the General Partner and its affiliates for reasonable costs and expenses of management. The reimbursement of expenses could adversely affect our ability to pay cash distributions to our unitholders. Our General Partner has sole discretion to determine the amount of these expenses, subject to the annual limit of 5% of an amount primarily based on our distributions to partners for that fiscal year. The annual limit includes carry-forward and carry-back features, which could allow costs in a year to exceed what would otherwise be the annual reimbursement limit. In addition, our General Partner and its affiliates may provide us with other services for which we will be charged fees as determined by our General Partner.

Our net income as reported for tax and financial statement purposes may differ significantly from our cash flow that is used to determine cash available for distributions.

Net income as reported for financial statement purposes is presented on an accrual basis in conformity with accounting principles generally accepted in the United States of America. Unitholder K-1 tax statements are calculated based on applicable tax conventions, and taxable income as calculated for each year will be allocated among unitholders who hold units on the last day of each month. Distributions, however, are calculated on the basis of actual cash receipts, changes in cash reserves, and disbursements during the relevant reporting period. Consequently, due to timing differences between the receipt of proceeds of production and the point in time at which the production giving rise to those proceeds actually occurs, net income reported on our consolidated financial statements and on unitholder K-1's will not reflect actual cash distributions during that reporting period.

Our unitholders have limited voting rights and do not control our General Partner, and their ability to remove our General Partner is limited.

Our unitholders have only limited voting rights on matters affecting our business. The general partner of our General Partner manages our activities. Our unitholders only have the right to annually elect the managers comprising the Advisory Committee of the Board of Managers of the general partner of our General Partner. Our unitholders do not have the right to elect the other managers of the general partner of our General Partner on an annual or any other basis.

Our General Partner may not be removed as our general partner except upon approval by the affirmative vote of the holders of at least a majority of our outstanding common units (including common units owned by our General Partner and its affiliates), subject to the satisfaction of certain conditions. Our General Partner and its affiliates do not own sufficient common units to be able to prevent its removal as general partner, but they do own sufficient common units to make the removal of our General Partner by other unitholders difficult.

These provisions may discourage a person or group from attempting to remove our General Partner or acquire control of us without the consent of our General Partner. As a result of these provisions, the price at which our common units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

The control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may withdraw or transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Other than some transfer restrictions agreed to among the owners of our General Partner relating to their interests in our General Partner, there is no restriction in our partnership agreement or otherwise for the benefit of our limited partners on the ability of the owners of our General Partner to transfer their ownership interests to a third party. The new owner of the General Partner would then be in a position to replace the management of our Partnership with its own choices.

Our General Partner and its affiliates have conflicts of interests, which may permit our General Partner and its affiliates to favor their own interests to the detriment of unitholders.

We and our General Partner and its affiliates share, and therefore compete for, the time and effort of General Partner personnel who provide services to us. Officers of our General Partner and its affiliates do not, and are not required to, spend any specified percentage or amount of time on our business. In fact, our General Partner has a duty to manage our Partnership in the best interests of our unitholders, but it also has a duty to operate its business for the benefit of its partners. Some of our officers are also involved in management and ownership roles in other oil and natural gas enterprises and have similar duties to them and devote time to their businesses. Because these shared officers function as both our representatives and those of our General Partner and its affiliates and of third parties, conflicts of interest could arise between our General Partner and its affiliates, on the one hand, and us or our unitholders, on the other, or between us or our unitholders on the one hand and the third parties for which our officers also serve management functions. As a result of these conflicts, our General Partner and its affiliates may favor their own interests over the interests of unitholders.

We may issue additional securities, diluting our unitholders' interests.

We can and may issue additional common units and other capital securities representing limited partnership units, including options, warrants, rights, appreciation rights and securities with rights to distributions and allocations or in liquidation equal or superior to our common units; however, a majority of the unitholders must approve such issuance if (i) the partnership securities to be issued will have greater rights or powers than our common units or (ii) if after giving effect to such issuance, such newly issued partnership securities represent over 40% of the outstanding limited partnership interests.

If we issue additional common units, it will reduce our unitholders' proportionate ownership interest in us. This could cause the market price of the common units to fall and reduce the per unit cash distributions paid to our unitholders. In addition, if we issued limited partnership units with voting rights superior to the common units, it could adversely affect our unitholders' voting power.

Our unitholders may not have limited liability in the circumstances described below and may be liable for the return of certain distributions.

Under Delaware law, our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our General Partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our General Partner generally has unlimited liability for the obligations of our Partnership, such as its debts and environmental liabilities, except for those contractual obligations of our Partnership that are expressly made without recourse to the General Partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under certain circumstances, a unitholder may be liable for the amount of distribution for a period of three years from the date of distribution.

Because we conduct our business in various states, the laws of those states may pose similar risks to our unitholders. To the extent to which we conduct business in any state, our unitholders might be held liable for our obligations as if they were general partners if a court or government agency determined that we had not complied with that state's partnership statute, or if rights of unitholders constituted participation in the "control" of our business under that state's partnership statute. In some of the states in which we conduct business, the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established.

We are dependent upon key personnel, and the loss of services of any of our key personnel could adversely affect our operations.

Our continued success depends to a considerable extent upon the abilities and efforts of the senior management of our General Partner, particularly William Casey McManemin, its Chief Executive Officer, Bradley J. Ehrman, its Chief Operating Officer and Leslie A. Moriyama, its Chief Financial Officer. The loss of the services of any of these key personnel could have a material adverse effect on the results of our operations. We have not obtained insurance or entered into employment agreements with any of these key personnel.

We are dependent on service providers who assist us with providing Schedule K-1 tax statements to our unitholders.

There are a very limited number of service firms that currently perform the detailed computations needed to provide each unitholder with estimated depletion and other tax information to assist the unitholder in various United States income tax computations. There are also very few publicly traded limited partnerships that need these services. As a result, the future costs and timeliness of providing Schedule K-1 tax statements to our unitholders is uncertain.

Tax Risk Factors

The tax consequences to a unitholder of the ownership and sale of common units will depend in part on the unitholder’s tax circumstances. Each unitholder should consult such unitholder’s own tax advisor about the federal, state and local tax consequences of the ownership of common units.

We generally do not obtain rulings or assurances from the IRS or state or local taxing authorities on matters affecting us.

We generally have not requested, and do not intend to request, rulings from the Internal Revenue Service, or IRS, or state or local taxing authorities with respect to owning and disposing of our common units or other matters affecting us. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of those conclusions or positions taken or expressed by us, and some or all of those conclusions or positions ultimately may not be sustained. Our unitholders and General Partner will bear, directly or indirectly, the costs of any contest with the IRS or other taxing authority. In 2020, we obtained a ruling from the IRS permitting us to aggregate the Minerals NPI, including the previously aggregated Maecenas NPI, Bradley NPI, Republic NPI, and Spinnaker NPI for federal income tax purposes effective January 1, 2020.

We will be subject to federal income tax and possibly certain state corporate income or franchise taxes if we are classified as a corporation and not as a partnership for federal income tax purposes.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. A change in our business or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 21%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Several states have subjected, or are evaluating ways to subject, partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. Therefore, treatment of us as a corporation or the assessment of a material amount of entity-level taxation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships.

Under current law, we believe that our royalty income is qualifying income for purposes of Section 7704(d)(1)(E) of the Internal Revenue Code (the “Code”). If the current law remains effective in its current form, we believe we will continue to be able to meet the qualifying income requirement. However, there can be no assurance that there will not be changes to the federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership for federal income tax purposes in the future.

Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to be treated as a partnership for federal income tax purposes or otherwise adversely affect us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

The recently enacted 20% deduction for certain pass-through income may not be available for our unitholders' allocable share of our net income, in which case our unitholders' tax liability with respect to ownership and disposition of our units may be materially higher than if the deduction is available.

For taxable years beginning after December 31, 2017 and ending on or before December 31, 2025, an individual taxpayer may generally claim a deduction in the amount of 20% of its allocable share of certain publicly traded partnership income, including generally, among other items, the net amount of its items of income, gain, deduction, and loss from a publicly traded partnership's U.S. trade or business. Because we own only non-operated, passive mineral and royalty interests, most or all of the income that we now generate, or will generate in the future, may not be "qualifying publicly traded partnership income" eligible for the 20% deduction. If the deduction is not available, our unitholders' tax liability from ownership and disposition of our units may be materially higher than if the deduction is available. We urge our unitholders to consult with their tax advisors regarding the availability of the 20% deduction on any income allocated from us.

The IRS could reallocate items of income, gain, deduction and loss between transferors and transferees of common units if the IRS does not accept our monthly convention for allocating such items.

In general, each of our items of income, gain, loss and deduction will, for federal income tax purposes, be determined annually, and one twelfth of each annual amount will be allocated to those unitholders who hold common units on the last business day of each month in that year. In certain circumstances we may make these allocations in connection with extraordinary or nonrecurring events on a more frequent basis. As a result, transferees of our common units may be allocated items of our income, gain, loss and deduction realized by us prior to the date of their acquisition of our common units. The U.S. Treasury Department has issued final Treasury regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferors and transferee unitholders. Nonetheless, if the IRS challenges our method of allocation, our income, gain, loss and deduction may be reallocated among our unitholders and our General Partner, and our unitholders may have more taxable income or less taxable loss. Our General Partner is authorized to revise our method of allocation between transferors and transferees, as well as among our other unitholders whose common units otherwise vary during a taxable period, to conform to a method permitted or required by the Code and the regulations or rulings promulgated thereunder.

Our unitholders may not be able to deduct losses attributable to their common units.

Any losses relating to our unitholders' common units will be losses related to portfolio income and their ability to use such losses may be limited.

Our unitholders' partnership tax information may be audited.

We will furnish our unitholders with a Schedule K-1 tax statement that sets forth their allocable share of income, gains, losses and deductions. In preparing this schedule, we will use various accounting and reporting conventions and various depreciation and amortization methods we have adopted. This schedule may not yield a result that conforms to statutory or regulatory requirements or to administrative pronouncements of the IRS. Further, our tax return may be audited, and any such audit could result in an audit of our unitholders' individual income tax returns as well as increased liabilities for taxes because of adjustments resulting from the audit. An audit of our unitholders' returns also could be triggered if the tax information relating to their common units is not consistent with the Schedule K-1 that we are required to provide to the IRS.

Our unitholders may have more taxable income or less taxable loss with respect to their common units if the IRS does not respect our method for determining the adjusted tax basis of their common units.

We have adopted a reporting convention that will enable our unitholders to track the basis of their individual common units or unit groups and use this basis in calculating their basis adjustments under Section 743 of the Code and gain or loss on the sale of common units. This method does not comply with an IRS ruling that requires a portion of the combined tax basis of all common units to be allocated to each of the common units owned by a unitholder upon a sale or disposition of less than all of the common units and may be challenged by the IRS. If such a challenge is successful, our unitholders may recognize more taxable income or less taxable loss with respect to common units disposed of and common units they continue to hold.

Tax-exempt investors may recognize unrelated business taxable income.

Generally, unrelated business taxable income, or UBTI, can arise from a trade or business unrelated to the exempt purposes of the tax-exempt entity that is regularly carried on by either the tax-exempt entity or a partnership in which the tax-exempt entity is a partner. However, UBTI does not apply to interest income, royalties (including overriding royalties) or net profits interests, whether the royalties or net profits are measured by production or by gross or taxable income from the property. Pursuant to the provisions of our partnership agreement, our General Partner shall use all reasonable efforts to prevent us from realizing income that would constitute UBTI. In addition, our General Partner is prohibited from incurring certain types and amounts of indebtedness and from directly owning working interests or cost bearing interests and, in the event that any of our assets become working interests or cost bearing interests, is required to assign such interests to the Operating Partnership subject to the reservation of a net profits overriding royalty interest. However, it is possible that we may realize income that would constitute UBTI in an effort to maximize unitholder value.

Our unitholders may be subject to withholding tax upon transfers of their common units.

If a unitholder sells or otherwise disposes of a common unit, the transferee generally is required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from distributions to the transferee amounts that should have been withheld by the transferee but were not withheld. Final regulations issued on October 7, 2020, provide rules for withholding on the transfer of a partnership interest in a publicly traded partnership. However, the Treasury Department and the IRS have suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our common units, that occur before January 1, 2023. For transfers of our common units occurring on or after January 1, 2023, withholding will be required on open market transactions, but in the case of a transfer made through a broker, a partner's share of liabilities will be excluded from the amount realized. In addition, the obligation to withhold will be imposed on the broker instead of the transferee (and we will generally not be required to withhold from the transferee amounts that should have been withheld by the transferee but were not withheld). Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

Tax consequences of certain NPIs are uncertain.

We are prohibited from owning working interests or cost-bearing interests. At the time of the creation of the Minerals NPI, we assigned to the Operating Partnership all rights in any such working interests or cost-bearing interests that might subsequently be created from the mineral properties that were and are subject of the Minerals NPI. As additional working interests and other cost-bearing interests are created out of such mineral properties, they are owned by the Operating Partnership pursuant to such original assignment, and we have executed various documents since the creation of the Minerals NPI to confirm such treatment under the original assignment. This treatment could be characterized differently by the IRS, and in such a case we are unable to predict, with certainty, all of the income tax consequences relating to the Minerals NPI as it relates to such working interests and other cost-bearing interests.

Our unitholders may not be entitled to deductions for percentage depletion with respect to our oil and natural gas interests.

Our unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to the oil and natural gas interests owned by us. However, percentage depletion is generally available to a unitholder only if the unitholder qualifies under the independent producer exemption contained in the Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative products or the operation of a major refinery. If a unitholder does not qualify under the independent producer exemption, the unitholder generally will be restricted to deductions based on cost depletion.

Our unitholders may have more taxable income or less taxable loss on an ongoing basis if the IRS does not accept our method of allocating depletion deductions.

The Code requires that income, gain, loss and deduction attributable to appreciated or depreciated property that is contributed to a partnership in exchange for a partnership interest be allocated so that the contributing partner is charged with, or benefits from, unrealized gain or unrealized loss, referred to as “Built-in Gain” and “Built-in Loss,” respectively, associated with the property at the time of its contribution to the partnership. Our partnership agreement provides that the adjusted tax basis of the oil and natural gas properties contributed to us is allocated to the contributing partners for the purpose of separately determining depletion deductions. Any gain or loss resulting from the sale of property contributed to us will be allocated to the partners that contributed the property, in proportion to their percentage interest in the contributed property, to take into account any Built-in Gain or Built-in Loss. This method of allocating Built-in Gain and Built-in Loss is not specifically permitted by the applicable Treasury regulations, and the IRS may challenge this method. Such a challenge, if successful, could cause our unitholders to recognize more taxable income or less taxable loss on an ongoing basis in respect of their common units.

Our unitholders may have more taxable income or less taxable loss on an ongoing basis if the IRS does not accept our method of determining a unitholder's share of the basis of partnership property.

Our General Partner utilizes a method of calculating each unitholder's share of the basis of partnership property that results in an aggregate basis for depletion purposes that reflects the purchase price of common units as paid by the unitholder. This method is not specifically authorized under applicable Treasury regulations, and the IRS may challenge this method. Such a challenge, if successful, could cause our unitholders to recognize more taxable income or less taxable loss on an ongoing basis in respect of their common units.

The ratio of the amount of taxable income that will be allocated to a unitholder to the amount of cash that will be distributed to a unitholder is uncertain, and cash distributed to a unitholder may not be sufficient to pay tax on the income we allocate to a unitholder.

The amount of taxable income realized by a unitholder will be dependent upon a number of factors, and so we cannot predict the ratio of the amount of taxable income that will be allocated to a unitholder to the amount of cash that will be distributed to a unitholder. Unitholders will be required to pay U.S. federal income taxes and, in some cases, state and local income taxes, on their share of taxable income, whether or not they receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

A unitholder may lose his status as a partner of our Partnership for federal income tax purposes if the unitholder lends our common units to a short seller to cover a short sale of such common units.

If a unitholder loans his common units to a short seller to cover a short sale of common units, the unitholder may be considered as having disposed of his ownership of those common units for federal income tax purposes. If so, the unitholder would no longer be a partner of our Partnership for tax purposes with respect to those common units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period, any of our income, gain, loss or deduction with respect to those common units would not be reportable, and any cash distributions received for those common units would be fully taxable and may be treated as ordinary income.

Foreign, state and local taxes could be withheld on amounts otherwise distributable to a unitholder.

A unitholder may be required to file tax returns and be subject to tax liability in the foreign, state or local jurisdictions where the unitholder resides and in each state or local jurisdiction in which we have assets or otherwise do business. We also may be required to withhold state income tax from distributions otherwise payable to a unitholder, and state income tax may be withheld by others on royalty payments to us.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We generally will have the ability to shift any such tax liability (including any applicable penalties and interest) to our General Partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so under all circumstances. If we are unable to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the economic burden resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

General Risk Factors

Public health threats could have an adverse effect on our Partnership, our cash flow and our industry.

Public health threats and other highly communicable diseases, outbreaks of which have been occurring in across the world, including the United States, could adversely impact our Partnership, drilling activities on our properties and the global economy.

In particular, the outbreak starting in 2020 of a coronavirus (COVID-19) has resulted in quarantines, restrictions on travel and a decrease in economic activity across the world, which has resulted in a decrease in demand for hydrocarbons. The COVID-19 pandemic and its ongoing variants may continue to have a material adverse effect on the demand for hydrocarbons and the prices at which they are sold, which may impact our revenues and operating income, our cash distributions and our business generally. It is impossible to predict the effect of the continued spread, or fear of continued spread, of COVID-19 and its ongoing variants globally. No assurance can be given that public health threats will not have a material adverse effect, and that any further spread of COVID-19 and its ongoing variants will not have a material adverse effect, on our business, operations and financial results.

Disclosure Regarding Forward-Looking Statements

Statements included in this report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "believe," "will," "expect," "anticipate," "estimate," "continue," or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other forward-looking information.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and, therefore, involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements for a number of important reasons, including those discussed under "Risk Factors" and elsewhere in this report. Examples of such reasons include, but are not limited to, changes in the price or demand for oil and natural gas, public health crises including the worldwide coronavirus (COVID-19) outbreak beginning in early 2020 and its ongoing variants, changes in the operations on or development of our properties, changes in economic and industry conditions and changes in regulatory requirements (including changes in environmental requirements) and our financial position, business strategy and other plans and objectives for future operations.

You should read these statements carefully because they may discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other forward-looking information. Before you invest, you should be aware that the occurrence of any of the events herein described in "Item 1A – Risk Factors" and elsewhere in this report and in the Partnership’s other filings with the Securities and Exchange Commission could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common units could decline, and you could lose all or part of your investment.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Facilities

Our corporate office is located in Dallas, Texas and consists of 11,847 square feet of leased office space.

Properties

We own two categories of properties: Royalty Properties and Net Profits Interests (“NPI”).

Royalty Properties

We own Royalty Properties representing producing and nonproducing mineral, royalty, overriding royalty, net profit and leasehold interests in properties located in 582 counties and parishes in 26 states. Acreage amounts listed herein represent our best estimates based on information provided to us as a royalty owner. Due to the significant number of individual deeds, leases and similar instruments involved in the acquisition and development of the Royalty Properties by us or our predecessors, acreage amounts are subject to change as new information becomes available. In addition, as a royalty owner, our access to information concerning activity and operations on the Royalty Properties is limited. Most of our producing properties are subject to old leases and other contracts pursuant to which we are not entitled to well information. Some of our newer leases provide for access to technical data and other information. We may have limited access to public data in some areas through third-party subscription services. Consequently, the exact number of wells producing from or drilling on the Royalty Properties at a given point in time is not easily determinable. The primary manner by which we will become aware of activity on the Royalty Properties is the receipt of division orders or other correspondence from operators or purchasers.

Acreage Summary

The following table sets forth, as of December 31, 2021, a summary of our gross and net acres, where applicable, of mineral, royalty, overriding royalty and leasehold interests, and a compilation of the number of counties and parishes and states in which these interests are located. The majority of our net mineral acres are unleased.

	Mineral	Royalty	Overriding Royalty	Leasehold
Number of States	26	17	17	8
Number of Counties/Parishes	504	192	147	32
Gross Acres	2,793,000	633,000	279,000	23,000
Net Acres (where applicable)	454,000	-	-	-

Our net interest in production from royalty, overriding royalty and leasehold interests is based on lease royalty and other third-party contractual terms, which vary from property to property. Consequently, net acreage ownership in these categories is not determinable. Our net interest in production from properties in which we own a royalty or overriding royalty interest may be affected by royalty terms negotiated by the previous mineral interest owners in such tracts and their lessees. Our interest in the majority of these properties is perpetual in nature. However, a minor portion of the properties are subject to terms and conditions pursuant to which a portion of our interest may terminate upon cessation of production.

The following table sets forth, as of December 31, 2021, the combined summary of total gross and net acres, where applicable, of mineral, royalty, overriding royalty and leasehold interests in each of the states in which these interests are located.

State	Gross	Net	State	Gross	Net
Alabama	105,000	8,000	**Missouri**	< 500	< 500
Arkansas	49,000	16,000	**Montana**	366,000	81,000
Colorado	24,000	1,000	**Nebraska**	3,000	< 500
Florida	89,000	25,000	**New Mexico**	47,000	3,000
Georgia	4,000	1,000	**New York**	23,000	19,000
Idaho	17,000	2,000	**North Dakota**	523,000	82,000
Illinois	5,000	1,000	**Oklahoma**	273,000	19,000
Indiana	< 500	< 500	**Oregon**	6,000	1,000
Kansas	14,000	2,000	**Pennsylvania**	10,000	6,000
Kentucky	2,000	1,000	**South Dakota**	55,000	11,000
Louisiana	133,000	3,000	**Texas**	1,808,000	159,000
Michigan	54,000	3,000	**Utah**	6,000	< 500
Mississippi	81,000	9,000	**Wyoming**	29,000	1,000

Leasing Activity

We received $0.8 million during 2021 attributable to lease bonus on 15 leases or extension of existing leases and one pooling election in lands located in eight counties in four states. These leases reflected bonus payments ranging up to $2,500/acre and initial royalty terms ranging up to 25%. The following table sets forth a summary of leases and pooling elections consummated during 2021 and 2020.

	2021	2020
Number	16	14
Number of States	4	2
Number of Counties/Parishes	8	9
Average Royalty(1)	19.9%	21.9%
Average Bonus, $/acre(1)	$ 787	$ 995
Total Lease Bonus	$ 0.8 million	$ 0.3 million

(1) Based on net acreage weighted average.

Payments received for gas storage, shut-in and delay rental payments, coal royalty, surface use agreements, litigation judgments and settlement proceeds are reflected in our accompanying consolidated financial statements in other operating revenues.

Net Profits Interests

We own a net profits overriding royalty interest (referred to as the Net Profits Interest, or "NPI") in various properties owned by Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our General Partner. We refer to Dorchester Minerals Operating LP as the "Operating Partnership." We receive monthly payments from the NPI equaling 96.97% of the net profits actually realized by the Operating Partnership from these properties in the preceding month. In the event costs, including budgeted capital expenditures, exceed revenues on a cash basis in a given month for properties subject to a Net Profits Interest, no payment is made, and any deficit is accumulated and reflected in the following month's calculation of net profit. In the event an NPI has a deficit of cumulative revenue versus cumulative costs, the deficit will be borne solely by the Operating Partnership. In 2020 we obtained a ruling from the IRS permitting the aggregation of the Minerals NPI, Bradley NPI, Republic NPI, and Spinnaker NPI for federal income tax purposes effective January 1, 2020. The Bradley NPI, Republic NPI, and Spinnaker NPI were aggregated into the Minerals NPI on a prospective basis in our financial results effective October 1, 2020.

From a cash perspective, as of December 31, 2021, the Minerals NPI was in a surplus position and had outstanding capital commitments, primarily in the Bakken region, equaling cash on hand of $2.0 million.

Acreage Summary

The following tables set forth, as of December 31, 2021, information concerning properties owned by the Operating Partnership and subject to the NPI. Acreage amounts listed under "Leasehold" reflect gross acres leased by the Operating Partnership and the working interest share (net acres) in those properties. Acreage amounts listed under "Mineral" reflect gross acres in which the Operating Partnership owns a mineral interest and the undivided mineral interest (net acres) in those properties. The Operating Partnership's interest in these properties may be unleased, leased by others or a combination thereof. In addition to amounts listed below, the Operating Partnership owns interests limited to certain wellbores located on lands in which we own mineral, royalty or leasehold interests. The acreage amounts associated with the wellbore interests are included in Royalty Properties Acreage Summary and not in the table below.

	Mineral	Royalty	Leasehold
Number of States	12	5	5
Number of Counties/Parishes	61	22	13
Gross Acres	50,000	-	14,000
Net Acres	6,000	-	2,000

The following table reflects the states in which the acreage amounts listed above are located.

	Mineral/Royalty		Leasehold		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	1,000	< 500	8,000	1,000	9,000	1,000
North Dakota	4,000	1,000	< 500	< 500	4,000	1,000
All Others	44,000	4,000	6,000	< 500	50,000	4,000

The leasehold acreage in Arkansas listed above includes all of the acreage in the Fayetteville Shale properties in which the Operating Partnership participates as a working interest owner.

Productive Well Summary

The following table sets forth, as of December 31, 2021, the approximate combined number of producing wells on the properties subject to the NPI. Gross wells refer to wells in which a working interest is owned. Net wells are determined by multiplying gross wells by our working interest in those wells.

	Productive Wells/Units(1)	
	Gross	Net
Texas	360	13
North Dakota	444	8
All others	274	9
Total	1,078	30

(1) Defined as all wells/units for which we received production revenue during the calendar year. Large, multi-well units paid on an aggregate basis are included as one gross well.

Drilling Activity

The following table sets forth first payments received for new wells completed on our Royalty Properties and NPI Properties during 2021. The majority of the activity was concentrated in the Permian Basin and Bakken region. Included in the table below are wells in which we own both a royalty interest and a net profits interest. Wells with such overlapping interests are counted in both categories.

	Royalty Properties(1)	Net Profits Interest
Gross Wells	725	45
Net Wells	4	< 1
Number of States	8	2
Number of Counties/Parishes	51	6

(1) 333 gross and 2 net royalty well additions in four counties in North Dakota are attributable to the JSFM acquisition that closed on June 30, 2021.

We have and will continue to consider a range of transaction structures for our unleased mineral interests including leasing to third parties, working interest participation through the Operating Partnership, electing non-consent under State laws, or a combination thereof.

Oil and Natural Gas Reserves

The below table reflects the Partnership's proved developed producing reserves at December 31, 2021. The reserves are based on the reports of independent petroleum engineering consulting firm LaRoche Petroleum Consultants, Ltd. LaRoche Petroleum Consultants, Ltd. is registered with the Engineering Board of the State of Texas. The LaRoche firm has been engaged in the business of oil and natural gas property evaluation since its formation in 1979. Other than our filings with the SEC, we have not filed the estimated proved reserves with, or included them in any reports to, any federal agency. Copies of the reports prepared by LaRoche Petroleum Consultants, Ltd. are attached hereto as Exhibits 99.1 and 99.2.

The Partnership does not have information that would be available to a company with oil and natural gas operations because detailed information is not generally available to owners of royalty interests. The Partnership's Chief Operating Officer ("COO") gathers production information and provides such information to our independent petroleum engineering consulting firm who extrapolates from such information estimates of the reserves attributable to the Royalty Properties and NPI based on their expertise in the oil and natural gas fields where the Royalty Properties and NPI are situated, as well as publicly available information. Ensuring compliance with generally accepted petroleum engineering and evaluation methods and procedures is the responsibility of the COO. Our COO has a bachelor's degree in Petroleum Engineering from the University of Alberta and has worked in the upstream oil and natural gas business in various capacities since 1996. The COO reports directly to the Chief Executive Officer ("CEO").

Summary of Oil and Gas Reserves as of Fiscal Year-End
All Proved Developed Producing and located in the United States

	Royalty Properties		Net Profits Interests(1)(2)		Total	
Year	Oil(3) (mbbls)	Natural Gas (mmcf)	Oil(3) (mbbls)	Natural Gas (mmcf)	Oil(3) (mbbls)	Natural Gas (mmcf)
2021	7,684	31,364	1,491	6,535	9,175	37,899
2020	7,778	29,964	1,566	3,815	9,344	33,779
2019	7,799	30,990	1,839	14,870	9,638	45,860

(1) Reserves reflect 96.97% of the corresponding amounts assigned to the Operating Partnership's interests in the properties underlying the Net Profits Interests.
(2) During 2020, the Partnership and affiliates of its General Partner closed the divestitures of our Hugoton and HHC net profits interests. The Hugoton and HHC net profits interests properties represented 408 mbbls and 9,377 mmcf of fiscal year-end 2019 reserves.
(3) Oil reserves include volumes attributable to natural gas liquids.

Proved oil and natural gas reserves means those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and governmental regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. See "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations" for average sales prices.

Title to Properties

We believe we have satisfactory title to all of our assets. Record title to essentially all of our assets has undergone the appropriate filings in the jurisdictions in which such assets are located. Title to property may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of our properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

ITEM 3. LEGAL PROCEEDINGS

The Partnership and the Operating Partnership are involved in legal and/or administrative proceedings arising in the ordinary course of their businesses, none of which have predictable outcomes and none of which are believed to have any significant effect on our financial position or operating results.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units trade on the NASDAQ Global Select Market under the ticker symbol "DMLP".

As of December 31, 2021, there were 13,840 common unitholders.

Issuer Purchases of Equity Securities

Period	(a) Total Number of Units Purchased	(b) Average Price Paid per Unit	(c) Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Units that May Yet Be Purchased Under the Plans or Programs
October 1, 2021 – October 31, 2021	-	N/A	-	89,259(1)
November 1, 2021 – November 30, 2021	10,375(2)	$ 19.21	10,375	78,884(1)
December 1, 2021 – December 31, 2021	-	N/A	-	78,884(1)
Total	10,375	$ 19.21	10,375	78,884(1)

(1) The number of common units that the Operating Partnership may grant under the Dorchester Minerals Operating LP Equity Incentive Program, which was approved by our common unitholders on May 20, 2015 (the "Equity Incentive Program"), each fiscal year may not exceed 0.333% of the number of common units outstanding at the beginning of the fiscal year. In 2021, the maximum number of common units that could be purchased under the Equity Incentive Program is 115,484 common units.

(2) Open-market purchases by the Operating Partnership, an affiliate of the Partnership, pursuant to a Rule 10b5-1 plan adopted on March 11, 2021 for the purpose of satisfying equity awards to be granted pursuant to the Equity Incentive Program.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Objective

This discussion, which presents our results of operations for the fiscal years ended December 31, 2021, and December 31, 2020, should be read in conjunction with our Consolidated Financial Statements and the accompanying notes. We intend for this discussion to provide the reader with information that will assist in understanding our financial statements, the changes in certain key items in those financial statements from period to period, and the primary factors that accounted for those changes.

2021 Overview

Our results during 2021 to a large extent benefitted from industrywide increases in realized oil and natural gas sales prices and increases in Royalty Properties sales volumes from continued drilling activity in the Permian Basin, offset partially by decreases in drilling activity and NPI oil sales volumes in the Bakken and a decrease in NPI natural gas sales due to the divestiture of the Hugoton NPI in 2020. Significant results include the following:

- Net income of $70.2 million;

- Distributions of $53.9 million to our limited partners;

- Acquisition of mineral and royalty interests representing approximately 4,600 net royalty acres located in 27 counties across New Mexico, Oklahoma, Texas and Wyoming in exchange for 1,580,000 common units representing limited partnership interests in the Partnership valued at $31.3 million and issued pursuant to the Partnership's registration statement on Form S-4;

- Acquisition of overriding royalty interests in the Bakken Trend totaling approximately 6,400 net royalty acres located in Dunn, McKenzie, McLean and Mountrail Counties, North Dakota in exchange for 725,000 common units representing limited partnership interests in the Partnership valued at $12.2 million and issued pursuant to the Partnership's registration statement on Form S-4;

- First payments on 725 gross and four net new wells completed on our Royalty Properties and 45 gross and less than one net new well completed on our NPI Properties. The wells were located in 51 counties and parishes in eight states with the majority of the activity concentrated in the Permian Basin and Bakken. Included in these totals are wells in which we own both a royalty interest and a net profits interest. Wells with such overlapping interests are counted in both categories;

- Total lease bonus of $0.8 million includes consummation of 16 leases and pooling elections of our mineral interest in undeveloped properties located in eight counties in four states.

Critical Accounting Estimates

The Partnership's consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United State ("U.S. GAAP"), which requires us to make certain estimates and apply judgments that affect our financial position and results of operations as reflected in our financial statements. Actual results may differ from those estimates. The Partnership's accounting policies are summarized in Note 1 of the Notes to Consolidated Financial Statements in "Item 8 – Financial Statements and Supplementary Data".

Management continually reviews our accounting policies, how they are applied, and how they are reported and disclosed in our financial statements. The following items require significant estimation or judgment:

Oil and Natural Gas Properties

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this method, all such costs are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. These capitalized costs are subject to a ceiling test, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties.

The discounted present value of our proved oil and natural gas reserves is a major component of the ceiling test calculation and requires many subjective judgments. Estimates of reserves are forecasts based on engineering and geological analyses. Different reserve engineers could reach different conclusions as to estimated quantities of oil and natural gas reserves based on the same information. The passage of time provides more qualitative and quantitative information regarding reserve estimates, and revisions are made to prior estimates based on updated information. However, there can be no assurance that more significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to income. In addition to the impact on the calculation of the ceiling test, estimates of proved reserves are also a major component of the calculation of depletion.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of our reserves are objectively determined. The ceiling test calculation requires use of the unweighted arithmetic average of the first day of the month price during the 12-month period ending on the balance sheet date and costs in effect as of the last day of the accounting period, which are generally held constant for the life of the properties. As a result, the present value is not necessarily an indication of the fair value of the reserves. Oil and natural gas prices have historically been volatile, and the prevailing prices at any given time may not reflect our Partnership's or the industry's forecast of future prices.

Revenue Recognition

The pricing of oil and natural gas sales from the Royalty Properties and NPI is primarily determined by supply and demand in the marketplace and can fluctuate considerably. As a royalty owner, we have extremely limited involvement and no operational control over the volumes and method of sale of oil and natural gas produced and sold from the Royalty Properties and NPI.

Revenues from Royalty Properties and NPI are recorded under the cash receipts approach as directly received from the remitters' statement accompanying the revenue check. Since the revenue checks are generally received two to four months after the production month, the Partnership accrues for revenue earned but not received by estimating production volumes and product prices. Estimates of uncollected revenues and unpaid expenses from Royalty Properties (which are interests in oil and natural gas leases that give the Partnership the right to receive a portion of the production from the leased acreage, without bearing the costs of such production) and net profits overriding royalty interests (referred to as the Net Profits Interest, or "NPI") operated by nonaffiliated entities are particularly subjective due to our inability to gain accurate and timely information. Identified differences between our accrued revenue estimates and actual revenue received historically have not been significant.

The Partnership does not record revenue for unsatisfied or partially unsatisfied performance obligations. The Partnership's right to revenues from Royalty Properties and NPI occurs at the time of production, at which point, payment is unconditional, and no remaining performance obligation exists for the Partnership. Accordingly, the Partnership's revenue contracts for Royalty Properties and NPI do not generate contract assets or liabilities.

Results of Operations

Normally, our period-to-period changes in net income and cash flows from operating activities are principally determined by changes in oil and natural gas sales volumes and prices, and to a lesser extent, by capital expenditures deducted under the NPI calculation. Our portion of oil and natural gas sales volumes and average sales prices are shown in the following table.

	Years Ended December 31,		
Accrual basis sales volumes:	**2021**	**2020**	**Change %**
Royalty Properties natural gas sales (mmcf)	3,665	3,484	5%
Royalty Properties oil sales (mbbls)	1,007	921	9%
NPI natural gas sales (mmcf)	1,344	2,297	(41)%
NPI oil sales (mbbls)	380	538	(29)%
Accrual basis average sales price:			
Royalty Properties natural gas sales ($/mcf)	$ 3.63	$ 1.58	130%
Royalty Properties oil sales ($/bbl)	$ 60.26	$ 34.24	76%
NPI natural gas sales ($/mcf)	$ 4.14	$ 1.33	211%
NPI oil sales ($/bbl)	$ 60.68	$ 32.27	88%

Comparison of the years ended December 31, 2021 and 2020

The increase in oil sales volumes attributable to our Royalty Properties during 2021 is primarily a result of higher suspense releases on new wells in the Permian Basin and Bakken region, partially offset by lower suspense releases on new wells in the Rockies and natural production declines in the Permian Basin, Bakken region, and Mid-Continent. The increase in natural gas sales volumes attributable to our Royalty Properties during 2021 is primarily a result of higher suspense releases on new wells in the Permian Basin and Mid-Continent and increased production in the Bakken region and Barnett Shale, partially largely offset by lower suspense releases on new wells in the Rockies, natural production declines in the Mid-Continent, and decreased production in other areas of Texas and the Southeast region.

The decrease in oil sales volumes attributable to our NPI properties during 2021 is primarily a result of lower suspense releases for new wells in the Bakken region and Permian Basin and natural production declines across all regions. The decrease in natural gas sales volumes attributable to our NPI properties during 2021 is primarily the result of the absence of 2021 production from the Hugoton Field due to the Hugoton NPI divestiture in the third quarter of 2020 and decreased production in Mid-Continent, partially offset by increased production in the Bakken region and increased Fayetteville Shale production due to higher prior period adjustments in the second quarter of 2021.

Production taxes and operating expenses increased 33% from 2020 to 2021. The increase is primarily a result of higher production taxes attributable to higher oil and natural gas sales prices, partially offset by lower ad valorem taxes.

Depreciation, depletion and amortization decreased 12% from 2020 to 2021. We adjust our depletion rate each quarter for significant changes in our estimates of oil and natural gas reserves, including acquisitions and divestitures.

General and administrative expenses decreased 31% from 2020 to 2021. The decrease is primarily a result of lower compensation expenses due to the forgiveness of the Operating Partnership's $0.9 million and $0.8 million Paycheck Protection Program loans in the second and third quarter of 2021, respectively, which were applied as non-recurring credits of compensation costs previously reimbursed between the Partnership and the Operating Partnership. The remainder of the decrease is attributable to non-recurring Hugoton and Huffman NPI divestiture transaction and severance costs of $1.0 million in 2020 and lower information technology project costs. These decreases were partially offset by higher compensation expenses due to the reduction of overhead billed to two NPIs which were divested in 2020.

Net cash provided by operating activities increased 78% from 2020 to 2021. The increase is primarily a result of higher Royalties revenue receipts, net of production taxes and operating expenses paid and lower compensation expenses paid due to the forgiveness of the Operating Partnership's $0.9 million and $0.8 million Paycheck Protection Program loans in the second and third quarter of 2021, respectively, which were applied as non-recurring credits of compensation costs previously reimbursed between the Partnership and the Operating Partnership.

Acquisition for Units

On December 31, 2021, pursuant to a non-taxable contribution and exchange agreement with Gemini 5 Thirty, LP, a Texas limited partnership ("Gemini"), the Partnership acquired mineral and royalty interests representing approximately 4,600 net royalty acres located in 27 counties across New Mexico, Oklahoma, Texas and Wyoming in exchange for 1,580,000 common units representing limited partnership interests in the Partnership valued at $31.3 million and issued pursuant to the Partnership's registration statement on Form S-4. We believe that the acquisition is considered complimentary to our business. The transaction was accounted for as an acquisition of assets under U.S. GAAP. Accordingly, the cost of the acquisition was allocated on a relative fair value basis and transaction costs were capitalized as a component of the cost of the assets acquired. At closing, in addition to conveying mineral and royalty interests to the Partnership, Gemini delivered funds to the Partnership in an amount equal to their cash receipts during the period from October 1, 2021 through December 31, 2021 of $1.9 million. The contributed cash, net of capitalized transaction costs paid, of $1.6 million is included in net cash contributed in acquisitions on the consolidated statement of cash flows for the year ended December 31, 2021.

On June 30, 2021, pursuant to a contribution and exchange agreement with JSFM, LLC, a Wyoming limited liability company ("JSFM"), the Partnership acquired overriding royalty interests in the Bakken Trend totaling approximately 6,400 net royalty acres located in Dunn, McKenzie, McLean and Mountrail Counties, North Dakota in exchange for 725,000 common units representing limited partnership interests in the Partnership valued at $12.2 million and issued pursuant to the Partnership's registration statement on Form S-4. We believe that the acquisition is considered complimentary to our business. The transaction was accounted for as an acquisition of assets under U.S. GAAP. Accordingly, the cost of the acquisition was allocated on a relative fair value basis and transaction costs were capitalized as a component of the cost of the assets acquired. At closing, in addition to conveying overriding royalty interests to the Partnership, JSFM delivered funds to the Partnership in an amount equal to their cash receipts during the period from April 1, 2021 through June 30, 2021 of $0.4 million. The contributed cash and final settlement net cash receipts, net of capitalized transaction costs paid, of $0.7 million are included in the net cash contributed in acquisition on the consolidated statement of cash flows for the year ended December 31, 2021.

Net Profits Interest Divestiture

On September 30, 2020, the Partnership and affiliates of its General Partner closed the divestiture of our Hugoton net profits interest located in Texas County, Oklahoma and Stevens County, Kansas to a third party. In accordance with the full cost method of accounting, as the divestiture did not represent a significant portion of the Partnership's reserves, gross divestiture proceeds of $5.7 million were credited to the oil and natural gas properties full cost pool as of December 31, 2020. Transaction costs of $0.5 million are included in general and administrative expenses on the consolidated income statement for the year ended December 31, 2020.

Texas Margin Tax

Texas imposes a franchise tax (commonly referred to as the Texas margin tax) at a rate of 0.75% on gross revenues less certain deductions, as specifically set forth in the Texas margin tax statute. The Texas margin tax applies to corporations and limited liability companies, general and limited partnerships (unless otherwise exempt), limited liability partnerships, trusts (unless otherwise exempt), business trusts, business associations, professional associations, joint stock companies, holding companies, joint ventures and certain other business entities having limited liability protection.

Limited partnerships that receive at least 90% of their gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas margin tax as "passive entities." We believe our Partnership meets the requirements for being considered a "passive entity" for Texas margin tax purposes and, therefore, it is exempt from the Texas margin tax. If the Partnership is exempt from Texas margin tax as a passive entity, each unitholder that is considered a taxable entity under the Texas margin tax would generally be required to include its portion of Partnership revenues in its own Texas margin tax computation. The Texas Administrative Code provides such income is sourced according to the principal place of business of the Partnership, which would be the state of Texas.

Each unitholder is urged to consult an independent tax advisor regarding the requirements for filing state income, franchise and Texas margin tax returns.

Liquidity and Capital Resources

Capital Resources

Our primary sources of capital, on both a short-term and long-term basis, are our cash flows from the Royalty Properties and the NPI. Our partnership agreement requires that we distribute quarterly an amount equal to all funds that we receive from the Royalty Properties and NPIs (other than cash proceeds received by the Partnership from a public or private offering of securities of the Partnership) less certain expenses and reasonable reserves. Additional cash requirements include the payment of oil and natural gas production and property taxes not otherwise deducted from gross production revenues and general and administrative expenses incurred on our behalf and allocated to the Partnership in accordance with the partnership agreement. Because the distributions to our unitholders are, by definition, determined after the payment of all expenses actually paid by us, the only cash requirements that may create liquidity concerns for us are the payment of expenses. Because many of these expenses vary directly with oil and natural gas sales prices and volumes, we anticipate that sufficient funds will be available at all times for payment of these expenses. See below for the dates of cash distributions to unitholders.

Contractual Obligations

The Partnership leases its office space at 3838 Oak Lawn Avenue, Suite 300, Dallas, Texas, through an operating lease (the "Office Lease"). The third amendment to our Office Lease was executed in April 2017 for a term of 129 months, beginning June 1, 2018 and expiring in 2029. Under the third amendment to the Office Lease, monthly rental payments range from $25,000 to $30,000. Future maturities of Office Lease liabilities representing monthly cash rental payment obligations are summarized in Note 7 of the Notes to Consolidated Financial Statements in "Item 8 – Financial Statements and Supplementary Data".

We are not directly liable for the payment of any exploration, development or production costs. We do not have any transactions, arrangements or other relationships that could materially affect our liquidity or the availability of capital resources. We have not guaranteed the debt of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

Pursuant to the terms of the partnership agreement, we cannot incur indebtedness, other than trade payables, (i) in excess of $50,000 in the aggregate at any given time or (ii) which would constitute "acquisition indebtedness" (as defined in Section 514 of the Internal Revenue Code of 1986, as amended).

We currently expect to have sufficient liquidity to fund our distributions to unitholders and operations despite potential material uncertainties that may impact us as a result of the spread of COVID-19 and any ongoing variants and continued oil and natural gas market volatility. Although demand and market prices for oil and natural gas have recently increased due to the rising energy demand, we cannot predict events that may lead to future price volatility. Our ability to fund future distributions to unitholders may be affected by the prevailing economic conditions in the oil and natural gas market and other financial and business factors, including the evolution of COVID-19 and any ongoing variants, which are beyond our control. If market conditions were to change due to declines in oil prices or uncertainty created by COVID-19 or any ongoing variants and our revenues were reduced significantly or our operating costs were to increase significantly, our cash flows and liquidity could be reduced. Despite recent improvements, the current economic environment is volatile, and therefore, we cannot predict the ultimate impact on our liquidity or cash flows.

Liquidity and Working Capital

Cash and cash equivalents were $28.3 million as of December 31, 2021 and $11.2 million as of December 31, 2020.

Distributions

Distributions to limited partners and the General Partner related to cash receipts were as follows:

					In Thousands	
Year	**Quarter**	**Record Date**	**Payment Date**	**Per Unit Amount**	**Limited Partners**	**General Partner**
2020	4th	February 1, 2021	February 11, 2021	$ 0.242260	$ 8,402	$ 279
2021	1st	May 3, 2021	May 13, 2021	0.303441	10,523	374
2021	2nd	August 2, 2021	August 12, 2021	0.480528	17,013	602
2021	3rd	November 1, 2021	November 10, 2021	0.507608	17,972	647
	Total distributions paid in 2021				$ 53,910	$ 1,902
2022	4th	January 31, 2022	February 10, 2022	$ 0.639287	$ 23,644	$ 855

In general, the limited partners are allocated 96% of the Royalty Properties' net receipts and 99% of NPI net receipts.

Net Profits Interests

We receive monthly payments from the Operating Partnership equal to 96.97% of the net proceeds actually realized by the Operating Partnership from the properties underlying the Net Profits Interest (or "NPI"). The Operating Partnership retains the 3.03% balance of these net proceeds. Net proceeds generally reflect gross proceeds attributable to oil and natural gas production actually received during the month, less production costs actually paid during the same month, net of budgeted capital expenditures. Production costs generally reflect drilling, completion, operating and general and administrative costs and exclude depletion, amortization and other non-cash costs. The Operating Partnership made NPI payments to us totaling $11.0 million during October 2020 through September 2021, which payments reflected 96.97% of total net proceeds of $11.4 million realized from September 2020 through August 2021. Net proceeds realized by the Operating Partnership during September through November 2021 were reflected in NPI payments made during October through December 2021. These payments were included in the fourth quarter distribution paid February 10, 2022 and are excluded from this 2021 analysis.

Royalty Properties

Revenues from the Royalty Properties are typically paid to us with proportionate severance (production) taxes deducted and remitted by others. Additionally, we generally pay ad valorem taxes, general and administrative costs, and marketing and associated costs because royalties and lease bonuses generally do not otherwise bear operating or similar costs. After deduction of the costs described above, including cash reserves, our net cash receipts from the Royalty Properties during October 2020 through September 2021 were $44.8 million, of which $43.0 million (96%) was distributed to the limited partners and $1.8 million (4%) was distributed to the General Partner. Proceeds received by us from the Royalty Properties during October through December 2021 became part of the fourth quarter distribution paid in early 2022, which is excluded from this 2021 analysis.

Distribution Determinations

The actual calculation of distributions is performed each calendar quarter in accordance with our partnership agreement. The following calculation covering the period October 2020 through September 2021 demonstrates the method:

	In Thousands	
	Limited Partners	General Partner
4% of net cash receipts from Royalty Properties	$ -	$ 1,792
96% of net cash receipts from Royalty Properties	42,994	-
1% of NPI payments to our Partnership	-	110
99% of NPI payments to our Partnership	10,916	-
Total distributions	$ 53,910	$ 1,902
Operating Partnership share (3.03% of net proceeds)		344
Total General Partner share		$ 2,246
% of total	96%	4%

In summary, our limited partners received 96%, and our General Partner received 4% of the net cash generated by our activities and those of the Operating Partnership during this period. Due to these fixed percentages, our General Partner does not have any incentive distribution rights or other right or arrangement that will increase its percentage share of net cash generated by our activities or those of the Operating Partnership.

During the period October 2020 through September 2021, our Partnership's quarterly distribution payments to limited partners were based on all of its available cash. Available cash is defined as all cash and cash equivalents on hand at the end of that quarter (other than cash proceeds received by the Partnership from public or private offering of securities of the Partnership), less any amount of cash reserves that our General Partner determines is necessary or appropriate to provide for the conduct of its business or to comply with applicable laws or agreements or obligations to which we may be subject. Our practice is to accrue funds quarterly for amounts incurred throughout the year but invoiced and paid annually or semi-annually (e.g. ad valorem taxes and professional services). These amounts generally are not held for periods over one year.

Fourth Quarter 2021 Distribution Indicated Price

In an effort to provide information concerning prices of oil and natural gas sales that correspond to our quarterly distributions, management calculates the average price by dividing gross revenues received by the net volumes of the corresponding product without regard to the timing of the production to which such sales may be attributable. This “indicated price” does not necessarily reflect the contractual terms for such sales and may be affected by transportation costs, location differentials, and quality and gravity adjustments. While the relationship between the Partnership's cash receipts and the timing of the production of oil and natural gas may be described generally, actual cash receipts may be materially impacted by purchasers’ release of suspended funds and by prior period adjustments.

Cash receipts attributable to the Partnership's Royalty Properties during the 2021 fourth quarter totaled $21.2 million. Approximately 82% of these receipts reflect oil sales during September 2021 through November 2021 and natural gas sales during August 2021 through October 2021, and approximately 18% from prior sales periods. The average indicated prices for oil and natural gas sales during the 2021 fourth quarter attributable to the Royalty Properties were $68.46/bbl and $4.15/mcf, respectively.

Cash receipts attributable to the Partnership's NPI during the 2021 fourth quarter totaled $4.2 million. Approximately 77% of these receipts reflect oil sales and natural gas sales during August 2021 through October 2021, and approximately 23% from prior sales periods. The average indicated prices for oil and natural gas sales during the 2021 fourth quarter attributable to the NPI were $68.11/bbl and $4.20/mcf, respectively.

General and Administrative Costs

In accordance with our partnership agreement, we bear all general and administrative and other overhead expenses subject to certain limitations. We reimburse our General Partner for certain allocable costs, including rent, wages, salaries and employee benefit plans. This reimbursement is limited to an amount equal to the sum of 5% of our distributions plus certain costs previously paid. Through December 31, 2021, the reimbursement amounts actually paid or accrued were less than the limitation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements are set forth herein commencing on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2021. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2021, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Management acknowledges its responsibility for establishing and maintaining adequate internal control over financial reporting in accordance with Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934. Management has also evaluated the effectiveness of its internal control over financial reporting in accordance with generally accepted accounting principles within the guidelines of the Committee of Sponsoring Organizations of the Treadway Commission framework (2013). Based on the results of this evaluation, management has determined that the Partnership's internal control over financial reporting was effective as of December 31, 2021.

Changes in Internal Controls

There were no changes in our Partnership's internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2021, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to the 2022 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2021.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the 2022 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2021.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The information required by this item is incorporated herein by reference to the 2022 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2021.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to the 2022 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2021.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the 2022 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2021.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Schedules

(1) See the Index to Consolidated Financial Statements on page F-1.
(2) No schedules are required.
(3) The exhibits required by Item 601 of Regulation S-K are as follows:

Number	Description
3.1	Certificate of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.1 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.2	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.2 to Dorchester Minerals' Report on Form 10-K filed for the year ended December 31, 2002)
3.3	Amendment No. 1 to Amended and Restated Partnership Agreement of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.1 to Dorchester Minerals' Current Report on Form 8-K filed with the SEC on December 22, 2017)
3.4	Amendment No. 2 to Amended and Restated Partnership Agreement of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Report on Form 10-Q filed with the SEC on August 6, 2018)
3.5	Certificate of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.6	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.7	Certificate of Formation of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.7 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.8	Amended and Restated Limited Liability Company Agreement of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.6 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.9	Certificate of Formation of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.10	Limited Liability Company Agreement of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.11	Certificate of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.12	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.13	Certificate of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
3.14	Agreement of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
3.15	Certificate of Incorporation of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.13 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
3.16	Bylaws of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.14 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
4.1	Description of the Registrant's Securities (incorporated by reference to Exhibit 4.1 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2019)
10.1	Amended and Restated Business Opportunities Agreement dated as of December 13, 2001 by and between the Registrant, the General Partner, Dorchester Minerals Management GP LLC, SAM Partners, Ltd., Vaughn Petroleum, Ltd., Smith Allen Oil & Gas, Inc., P.A. Peak, Inc., James E. Raley, Inc., and certain other parties (incorporated by reference to Exhibit 10.1 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
10.2	Transfer Restriction Agreement (incorporated by reference to Exhibit 10.2 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
10.3	Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
10.4	Lock-Up Agreement by William Casey McManemin (incorporated by reference to Exhibit 10.4 to Dorchester Minerals' Annual Report on Form 10-K for the year ended December 31, 2002)
10.5	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.1 to Dorchester Minerals' Quarterly Report on Form 10-Q for the quarter ended June 30, 2004)

Number	Description
10.6	Dorchester Minerals Operating LP Equity Incentive Program (incorporated by reference to Annex A to Dorchester Minerals’ Proxy Statement on Schedule 14A filed with the SEC on March 16, 2015)
10.7	Contribution and Exchange Agreement dated November 22, 2021, by and between Dorchester Minerals, L.P. and Gemini 5 Thirty, LP (incorporated by reference to Exhibit 2.1 to Dorchester Minerals' Current Report on Form 8-K filed with the SEC on November 23, 2021)
21.1*	Subsidiaries of the Registrant
23.1*	Consent of Grant Thornton LLP
23.2*	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	Certification of Chief Executive Officer of our Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer of our Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Sec. 1350
99.1*	Report of LaRoche Petroleum Consultants, Ltd.
99.2*	Report of LaRoche Petroleum Consultants, Ltd.
101.INS*	XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

---

* Filed herewith
** Furnished herewith

ITEM 16. FORM 10-K SUMMARY

None.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The definitions set forth below shall apply to the indicated terms as used in this document. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

"bbl" means a standard barrel of 42 U.S. gallons and represents the basic unit for measuring the production of crude oil, natural gas liquids and condensate.

"*boe*" means one barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil. Also see mcfe below.

"Depletion" means (a) the volume of hydrocarbons extracted from a formation over a given period of time, (b) the rate of hydrocarbon extraction over a given period of time expressed as a percentage of the reserves existing at the beginning of such period, or (c) the amount of cost basis at the beginning of a period attributable to the volume of hydrocarbons extracted during such period.

"Division order" means a document to protect lessees and purchasers of production, in which all parties who may have a claim to the proceeds of the sale of production agree upon how the proceeds are to be divided.

"Enhanced recovery" means the process or combination of processes applied to a formation to extract hydrocarbons in addition to those that would be produced utilizing the natural energy existing in that formation. Examples of enhanced recovery include water flooding and carbon dioxide (CO_2) injection.

"Estimated future net revenues" (also referred to as "estimated future net cash flow") means the result of applying current prices of oil and natural gas to estimated future production from oil and natural gas proved reserves, reduced by estimated future expenditures, based on current costs to be incurred in developing and producing the proved reserves, excluding overhead.

"Formation" means a distinct geologic interval, sometimes referred to as the strata, which has characteristics (such as permeability, porosity and hydrocarbon saturations) that distinguish it from surrounding intervals.

"Gross acre" means the number of surface acres in which a working interest is owned.

"Gross well" means a well in which a working interest is owned.

"Lease bonus" means the initial cash payment made to a lessor by a lessee in consideration for the execution and conveyance of the lease and includes proceeds from assignments of leasehold interests where the Partnership retains an interest.

"Leasehold" means an acre in which a working interest is owned.

"Lessee" means the owner of a lease of a mineral interest in a tract of land.

"Lessor" means the owner of the mineral interest who grants a lease of his interest in a tract of land to a third party, referred to as the lessee.

"Mineral interest" means the interest in the minerals beneath the surface of a tract of land. A mineral interest may be severed from the ownership of the surface of the tract. Ownership of a mineral interest generally involves four incidents of ownership: (1) the right to use the surface; (2) the right to incur costs and retain profits, also called the right to develop; (3) the right to transfer all or a portion of the mineral interest; and (4) the right to retain lease benefits, including bonuses and delay rentals.

"mcf" means one thousand cubic feet under prescribed conditions of pressure and temperature and represents the basic unit for measuring the production of natural gas.

"*mcfe*" means one thousand cubic feet of natural gas equivalent, converting oil or condensate to natural gas at the ratio of 1 Bbl of oil or condensate to 6 Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas. The sales price of one barrel of oil or condensate has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to one barrel of oil or condensate

"mbbls" means one thousand standard barrels of 42 U.S. gallons and represents the basic unit for measuring the production of crude oil, natural gas liquids and condensate.

"mmcf" means one million cubic feet under prescribed conditions of pressure and temperature and represents the basic unit for measuring the production of natural gas.

"Net acre" means the product determined by multiplying gross acres by the interest in such acres.

"Net well" means the product determined by multiplying gross oil and natural gas wells by the interest in such wells.

"Net profits interest" means a non-operating interest that creates a share in gross production from another (operating or non-operating) interest in oil and natural gas properties. The share is determined by net profits from the sale of production and customarily provides for the deduction of capital and operating costs from the proceeds of the sale of production. The owner of a net profits interest is customarily liable for the payment of capital and operating costs only to the extent that revenue is sufficient to pay such costs but not otherwise.

"Operator" means the individual or company responsible for the exploration, development, and production of an oil or natural gas well or lease.

"Overriding royalty interest" means a royalty interest created or reserved from another (operating or non-operating) interest in oil and natural gas properties. Its term extends for the same term as the interest from which it is created.

"*Payout*" *or* "*Back-in*" occurs when the working interest owners who participate in the costs of drilling and completing a well recoup the costs and expenses, or a multiple of the costs and expenses, of drilling and completing that well. Only then are the owners who chose not to contribute to these initial costs entitled to participate with the other owners in production and share in the expenses and revenues associated with the well. The reversionary interest or back-in interest of an owner similarly occurs when the owner becomes entitled to a specified share of the working or overriding royalty interest when specified costs have been recovered from production.

"*Pooling election*" means the statutory combination of interests which affords owners the right to choose between participating in the drilling of a well or accepting royalty payments.

"Proved developed reserves" means reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved reserves" or "*Proved oil and natural gas reserves*" means those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and governmental regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"Royalty" means an interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof) but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage.

"Severance tax" means an amount of tax, surcharge or levy recovered by governmental agencies from the gross proceeds of oil and natural gas sales. Severance tax may be determined as a percentage of proceeds or as a specific amount per volumetric unit of sales. Severance tax is usually withheld from the gross proceeds of oil and natural gas sales by the first purchaser (e.g., pipeline or refinery) of production.

"Standardized measure of discounted future net cash flows" (also referred to as "standardized measure") means the pretax present value of estimated future net revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

"*Suspense release*" means revenues that have been held by a purchaser or lessee, often attributable to multiple months of production.

"Undeveloped acreage" means lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

"Unitization" means the process of combining mineral interests or leases thereof in separate tracts of land into a single entity for administrative, operating or ownership purposes. Unitization is sometimes called "pooling" or "communitization" and may be voluntary or involuntary.

"Working interest" (also referred to as an "operating interest") means a real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and certain activities in connection with the development and operation of a property.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP,
its General Partner

By: Dorchester Minerals Management GP LLC,
its General Partner

By: /s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer

Date: February 24, 2022

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer and Manager
(Principal Executive Officer)
Date: February 24, 2022

/s/ H.C. Allen, Jr.
H.C. Allen, Jr.
Manager
Date: February 24, 2022

/s/ James E. Raley
James E. Raley
Vice Chairman and Manager
Date: February 24, 2022

/s/ Allen D. Lassiter
Allen D. Lassiter
Manager
Date: February 24, 2022

/s/ Martha Ann Peak Rochelle
Martha Ann Peak Rochelle
Manager
Date: February 24, 2022

/s/ C. W. Russell
C. W. Russell
Manager
Date: February 24, 2022

/s/ Ronald P. Trout
Ronald P. Trout
Manager
Date: February 24, 2022

/s/ Robert C. Vaughn
Robert C. Vaughn
Manager
Date: February 24, 2022

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Dorchester Minerals, L.P.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders
Dorchester Minerals, L.P.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Dorchester Minerals, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2021 and 2020, the related consolidated statements of income, changes in partnership capital, and cash flows for each of the two years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion
These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters
Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that; (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgements. We determined that there are no critical audit matters.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 1998.

Dallas, Texas
February 24, 2022

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONSOLIDATED BALANCE SHEETS
December 31,
(In Thousands)

	2021	2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 28,306	$ 11,232
Trade and other receivables	11,533	5,075
Net profits interest receivable—related party	6,822	1,914
Total current assets	46,661	18,221
Oil and natural gas properties (full cost method)	440,052	399,324
Accumulated full cost depletion	(341,733)	(331,361)
Total	98,319	67,963
Leasehold improvements	989	989
Accumulated amortization	(330)	(238)
Total	659	751
Operating lease right-of-use asset	1,168	1,392
Total assets	$ 146,807	$ 88,327
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 2,512	$ 1,578
Operating lease liability	291	300
Total current liabilities	2,803	1,878
Operating lease liability	1,594	1,885
Total liabilities	4,397	3,763
Commitments and contingencies (Note 5)		
Partnership capital:		
General Partner	982	536
Unitholders	141,428	84,028
Total partnership capital	142,410	84,564
Total liabilities and partnership capital	$ 146,807	$ 88,327

The accompanying notes are an integral part of these consolidated financial statements

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONSOLIDATED INCOME STATEMENTS
For each of the Years Ended December 31,
(In Thousands, except per unit amounts)

	2021	2020
Operating revenues:		
Royalties	$ 73,985	$ 37,043
Net profits interests	17,596	8,714
Lease bonus	829	291
Other	1,013	880
Total operating revenues	93,423	46,928
Costs and expenses		
Production taxes	3,667	1,813
Operating expenses	3,929	3,880
Depreciation, depletion and amortization	10,464	11,909
General and administrative expenses	5,189	7,459
Total costs and expenses	23,249	25,061
Net income	$ 70,174	$ 21,867
Allocation of net income:		
General Partner	$ 2,348	$ 705
Unitholders	$ 67,826	$ 21,162
Net income per common unit (basic and diluted)	$ 1.94	$ 0.61
Weighted average basic and diluted common units outstanding	35,052	34,680

The accompanying notes are an integral part of these consolidated financial statements

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERSHIP CAPITAL
For each of the Years Ended December 31,
(In Thousands)

	General Partner	Unitholders	Total	Unitholder Units
2020				
Balance at January 1, 2020	$ 1,228	$ 111,108	$ 112,336	34,680
Net income	705	21,162	21,867	-
Distributions ($1.391063 per Unit)	(1,397)	(48,242)	(49,639)	-
Balance at December 31, 2020	$ 536	$ 84,028	$ 84,564	34,680
2021				
Net income	2,348	67,826	70,174	-
Acquisition of assets for units	-	43,484	43,484	2,305
Distributions ($1.533837 per Unit)	(1,902)	(53,910)	(55,812)	-
Balance at December 31, 2021	$ 982	$ 141,428	$ 142,410	36,985

The accompanying notes are an integral part of these consolidated financial statements

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONSOLIDATED STATEMENTS OF CASH FLOWS
For each of the Years Ended December 31,
(In Thousands)

	2021	2020
Cash flows from operating activities:		
Net income	$ 70,174	$ 21,867
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	10,464	11,909
Amortization of operating lease right-of-use asset	224	240
Changes in operating assets and liabilities:		
Trade and other receivables	(5,972)	2,206
Net profits interests receivable—related party	(4,908)	3,968
Accounts payable and other current liabilities	623	(474)
Operating lease liability	(300)	(310)
Net cash provided by operating activities	70,305	39,406
Cash flows provided by investing activities:		
Net cash contributed in acquisitions	2,319	-
Proceeds from the sale of oil and natural gas properties	262	6,126
Total cash flows provided by investing activities	2,581	6,126
Cash flows used in financing activities:		
Distributions paid to General Partner and unitholders	(55,812)	(49,639)
Increase (decrease) in cash and cash equivalents	17,074	(4,107)
Cash and cash equivalents at beginning of year	11,232	15,339
Cash and cash equivalents at end of year	$ 28,306	$ 11,232
Non-cash investing activities:		
Fair value of common units issued for acquisitions	$ 43,484	$ -

The accompanying notes are an integral part of these consolidated financial statements

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

Notes to Consolidated Financial Statements

1. General and Summary of Significant Accounting Policies

Nature of Operations — In these Notes, the term “Partnership,” as well as the terms “us,” “our,” “we,” and “its” are sometimes used as abbreviated references to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities. Our Partnership is a Dallas, Texas based owner of producing and nonproducing natural gas and crude oil royalty, net profits, and leasehold interests in 582 counties and 26 states. We are a publicly traded Delaware limited partnership that was formed in December 2001 and commenced operations on January 31, 2003.

Basis of Presentation — The consolidated financial statements herein have been prepared in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”).

Basic and Diluted Earnings Per Unit — Per-unit information is calculated by dividing the net income applicable to holders of our Partnership’s common units by the weighted average number of units outstanding. The Partnership has no potentially dilutive securities and, accordingly, basic and dilutive net income per unit do not differ.

Principles of Consolidation — The consolidated financial statements include the accounts of Dorchester Minerals, L.P., Dorchester Minerals Oklahoma, LP, Dorchester Minerals Oklahoma GP, Inc., Maecenas Minerals LLP, Dorchester-Maecenas GP LLC, The Buffalo Co., A Limited Partnership, and DMLPTBC GP LLC. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates —The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

General Partner—Our general partner is Dorchester Minerals Management LP, referred to in these Notes as “our General Partner.” Our General Partner owns all of the partnership interests in Dorchester Minerals Operating LP, the Operating Partnership. See Note 4 —Related Party Transactions. The General Partner is allocated 4% and 1% of our Royalty Properties’ net revenues and Net Profits Interest ("NPI") proceeds received by the Operating Partnership, respectively. The Royalty Properties consist of producing and nonproducing mineral, royalty, overriding royalty, net profits, and leasehold interests located in 582 counties and parishes in 26 states (“Royalty Properties”).

Cash and Cash Equivalents—Our principal banking relationships are with major financial institutions. Cash balances in these accounts may, at times, exceed federally insured limits. We have not experienced any losses in such cash accounts and do not believe we are exposed to any significant risk on cash and cash equivalents. Short term investments with an original maturity of three months or less are considered to be cash equivalents and are carried at cost, which approximates fair value.

Concentration of Credit Risks and Significant Customers—Our Partnership, as a royalty and NPI owner, has extremely limited involvement and no control over the volumes or method of sale of oil and natural gas produced and sold from the Royalty Properties and NPI. Royalty revenues from properties operated by Pioneer Natural Resources represented approximately 13% of total operating revenues for the year ended December 31, 2021. There were no concentrations of revenue with a single customer for the year ended December 31, 2020. If we were to lose a significant customer, such loss could impact revenue. The loss of any single customer is mitigated by our diversified customer base, and we do not believe that the loss of any single customer would have a long-term material adverse effect on our financial position or the results of operations.

Fair Value of Financial Instruments—The carrying amount of cash and cash equivalents, trade and other receivables, and accounts payables and other current liabilities approximates fair value because of the short maturity of those instruments. These estimated fair values may not be representative of actual values of the financial instruments that could have been realized as of year-end or that will be realized in the future.

Receivables—Our Partnership's trade and other receivables and net profits interests receivable consist primarily of Royalty Properties payments receivable and NPI payments receivable, respectively. Most payments are received two to four months after production date. No allowance for doubtful accounts is deemed necessary based upon our lack of historical write offs and review of current receivables.

Oil and Natural Gas Properties — We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this method, all such costs are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. These capitalized costs are subject to a ceiling test, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. For the purposes of determining the capitalized costs ceiling, our Partnership only assigned value to proved developed producing oil and natural gas reserves as of December 31, 2021. The full cost ceiling is evaluated at the end of each quarter and when events indicate possible impairment. There have been no impairments for the years ended December 31, 2021 and 2020.

The discounted present value of our proved oil and natural gas reserves is a major component of the ceiling test calculation and requires many subjective judgments. Estimates of reserves are forecasts based on engineering and geological analyses. Different reserve engineers could reach different conclusions as to estimated quantities of oil and natural gas reserves based on the same information. The passage of time provides more qualitative and quantitative information regarding reserve estimates, and revisions are made to prior estimates based on updated information. However, there can be no assurance that more significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to income. In addition to the impact on the calculation of the ceiling test, estimates of proved reserves are also a major component of the calculation of depletion.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of our reserves are objectively determined. The ceiling test calculation requires use of the unweighted arithmetic average of the first day of the month price during the 12-month period ending on the balance sheet date and costs in effect as of the last day of the accounting period, which are generally held constant for the life of the oil and natural gas properties. As a result, the present value is not necessarily an indication of the fair value of the reserves. Oil and natural gas prices have historically been volatile, and the prevailing prices at any given time may not reflect our Partnership's or the industry's forecast of future prices.

Gains and losses are recognized upon the disposition of oil and natural gas properties involving a significant portion (greater than 25%) of our Partnership's reserves. Proceeds from other dispositions of oil and natural gas properties are credited to the full cost pool.

Leasehold Improvements — Leasehold improvements are amortized over the shorter of their estimated useful lives or the related life of the lease.

Leases — The Partnership determines if an arrangement is a lease at inception. The Partnership leases its office space at 3838 Oak Lawn Avenue, Suite 300, Dallas, Texas, through an operating lease (the "Office Lease"). The operating lease is included in operating lease right-of-use ("ROU") asset and operating lease liability in our consolidated balance sheets. Operating lease expense is included in general and administrative expenses in the consolidated income statements.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. As the Partnership's lease does not provide an implicit rate of return and as the Partnership is precluded from incurring any borrowings above a nominal amount under its partnership agreement, the Partnership used a discount rate commensurate with the incremental borrowing rate of a group of peers based on information available at the application date in determining the present value of lease payments. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term.

Asset Retirement Obligations — Based on the nature of our property ownership, we have no material obligations to record.

Revenue Recognition — The pricing of oil and natural gas sales from the Royalty Properties and NPI is primarily determined by supply and demand in the marketplace and can fluctuate considerably. As a royalty owner, we have extremely limited involvement and no operational control over the volumes and method of sale of oil and natural gas produced and sold from the Royalty Properties and NPI.

Revenues from Royalty Properties and NPI are recorded under the cash receipts approach as directly received from the remitters' statement accompanying the revenue check. Since the revenue checks are generally received two to four months after the production month, the Partnership accrues for revenue earned but not received by estimating production volumes and product prices. Identified differences between our accrued revenue estimates and actual revenue received historically have not been significant.

The Partnership does not record revenue for unsatisfied or partially unsatisfied performance obligations. The Partnership's right to revenues from Royalty Properties and NPI occurs at the time of production, at which point, payment is unconditional, and no remaining performance obligation exists for the Partnership. Accordingly, the Partnership's revenue contracts for Royalty Properties and NPI do not generate contract assets or liabilities.

Revenues from lease bonus payments are recorded upon receipt. The lease bonus is separate from the lease itself and is recognized as revenue to the Partnership upon receipt of payment. The Partnership generates lease bonus revenue by leasing its mineral interests to exploration and production companies and includes proceeds from assignments of leasehold interests where the Partnership retains an interest. A lease agreement represents the Partnership's contract with a lessee and generally transfers the rights to develop oil or natural gas, grants the Partnership a right to a specified royalty interest, and requires that drilling and completion operations commence within a specified time period. Upon signing a lease agreement, no further performance obligation exists for the Partnership, and therefore, no contract assets or contract liabilities are generated.

Income Taxes — We are treated as a partnership for income tax purposes and, as a result, our income or loss is includable in the tax returns of the individual unitholders. Depletion of oil and natural gas properties is an expense allowable to each individual partner, and the depletion expense as reported on the consolidated financial statements will not be indicative of the depletion expense an individual partner or unitholder may be able to deduct for income tax purposes.

Texas imposes a franchise tax (commonly referred to as the Texas margin tax) at a rate of 0.75% on gross revenues less certain deductions, as specifically set forth in the Texas margin tax statute. The Texas margin tax applies to corporations and limited liability companies, general and limited partnerships (unless otherwise exempt), limited liability partnerships, trusts (unless otherwise exempt), business trusts, business associations, professional associations, joint stock companies, holding companies, joint ventures, and certain other business entities having limited liability protection.

Limited partnerships that receive at least 90% of their gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas margin tax as "passive entities." We believe our Partnership meets the requirements for being considered a "passive entity" for Texas margin tax purposes and, therefore, it is exempt from the Texas margin tax. If the Partnership is exempt from Texas margin tax as a passive entity, each unitholder that is considered a taxable entity under the Texas margin tax would generally be required to include its portion of Partnership revenues in its own Texas margin tax computation. The Texas Administrative Code provides that such income is sourced according to the principal place of business of the Partnership, which would be the state of Texas.

Recent Events – In January 2020, the World Health Organization ("WHO") announced a global health emergency because of a new strain of coronavirus ("COVID-19") and the significant risks to the international community and economies as the virus spreads globally beyond its point of origin. In March 2020, the WHO classified COVID-19 as a pandemic, based on the rapid increase in exposure globally, and thereafter, COVID-19 continued to spread throughout the U.S. and worldwide. In addition, actions taken by OPEC members and other exporting nations on the supply and demand in global oil and natural gas markets resulted in significant negative pricing pressure in the first half of 2020, followed by a recovery in pricing and an increase in demand in the second half of 2020 and into 2021. However, multiple variants emerged in 2021 and became highly transmissible, which contributed to additional pricing volatility during 2021 to date. The financial results of companies in the oil and natural gas industry have been impacted materially as a result of changing market conditions. Such circumstances generally increase uncertainty in the Partnership's accounting estimates. Although demand and market prices for oil and natural gas have recently increased, due to the rising energy use and the improvement in U.S. economic activity, we cannot predict events that may lead to future price volatility and the near term energy outlook remains subject to heightened levels of uncertainty.

We are continuing to closely monitor the overall impact and the evolution of the COVID-19 pandemic, including the ongoing spread of any variants, along with future OPEC actions on all aspects of our business, including how these events may impact our future operations, financial results, liquidity, employees, and operators. Additional actions may be required in response to the COVID-19 pandemic on a national, state, and local level by governmental authorities, and such actions may further adversely affect general and local economic conditions, particularly if the 2021 resurgence and spread of the COVID-19 pandemic continues. We cannot predict the long-term impact of these events on our liquidity, financial position, results of operations or cash flows due to uncertainties including the severity of COVID-19 or any of the ongoing variants, and the effect the virus will have on the demand for oil and natural gas. These situations remain fluid and unpredictable, and we are actively managing our response.

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

Notes to Consolidated Financial Statements

2. Acquisitions for Units

On December 31, 2021, pursuant to a non-taxable contribution and exchange agreement with Gemini 5 Thirty, LP, a Texas limited partnership ("Gemini"), the Partnership acquired mineral and royalty interests representing approximately 4,600 net royalty acres located in 27 counties across New Mexico, Oklahoma, Texas and Wyoming in exchange for 1,580,000 common units representing limited partnership interests in the Partnership valued at $31.3 million and issued pursuant to the Partnership's registration statement on Form S-4. We believe that the acquisition is considered complimentary to our business. The transaction was accounted for as an acquisition of assets under U.S. GAAP. Accordingly, the cost of the acquisition was allocated on a relative fair value basis and transaction costs were capitalized as a component of the cost of the assets acquired. At closing, in addition to conveying mineral and royalty interests to the Partnership, Gemini delivered funds to the Partnership in an amount equal to their cash receipts during the period from October 1, 2021 through December 31, 2021 of $1.9 million. The contributed cash, net of capitalized transaction costs paid, of $1.6 million is included in net cash contributed in acquisitions on the consolidated statement of cash flows for the year ended December 31, 2021. The consolidated balance sheet as of December 31, 2021 includes $29.3 million of net proved oil and natural gas properties acquired in the transaction.

On June 30, 2021, pursuant to a non-taxable contribution and exchange agreement with JSFM, LLC, a Wyoming limited liability company ("JSFM"), the Partnership acquired overriding royalty interests in the Bakken Trend totaling approximately 6,400 net royalty acres located in Dunn, McKenzie, McLean and Mountrail Counties, North Dakota in exchange for 725,000 common units representing limited partnership interests in the Partnership valued at $12.2 million and issued pursuant to the Partnership's registration statement on Form S-4. We believe that the acquisition is considered complimentary to our business. The transaction was accounted for as an acquisition of assets under U.S. GAAP. Accordingly, the cost of the acquisition was allocated on a relative fair value basis and transaction costs were capitalized as a component of the cost of the assets acquired. At closing, in addition to conveying overriding royalty interests to the Partnership, JSFM delivered funds to the Partnership in an amount equal to their cash receipts during the period from April 1, 2021 through June 30, 2021 of $0.4 million. The contributed cash and final settlement net cash receipts, net of capitalized transaction costs paid, of $0.7 million are included in the net cash contributed in acquisition on the consolidated statement of cash flows for the year ended December 31, 2021. The consolidated balance sheet as of December 31, 2021 includes $11.5 million of net proved oil and natural gas properties acquired in the transaction.

3. Net Profits Interest Divestiture

On September 30, 2020, the Partnership and affiliates of its General Partner closed the divestiture of our Hugoton net profits interest located in Texas County, Oklahoma and Stevens County, Kansas to a third party. In accordance with the full cost method of accounting, as the divestiture did not represent a significant portion of the Partnership's reserves, gross divestiture proceeds of $5.7 million were credited to the oil and natural gas properties full cost pool as of December 31, 2020. Transaction costs of $0.5 million are included in general and administrative expenses on the consolidated income statement for the year ended December 31, 2020.

4. Related Party Transactions

Our General Partner owns all of the partnership interests in the Operating Partnership. It is the employer of all personnel, owns the working interests and other properties underlying our NPI, and provides day-to-day operational and administrative services to us and the General Partner. In accordance with our partnership agreement, we reimburse the General Partner for certain allocable general and administrative costs, including rent, salaries, and employee equity and benefit plans that are not direct expenses. These types of reimbursements are limited to 5% of distributions, plus certain costs previously paid. All such costs have been below the annual 5% limit amount, including the allowable surplus carryforward, for the years ended December 31, 2021 and 2020. Additionally, certain reimbursable direct expenses such as professional and regulatory fees, as well as certain general and administrative costs that are related to regulatory matters, are not limited. Significant activity between the Partnership and the Operating Partnership consists of the following:

	In Thousands	
	2021	**2020**
Net profits interest receivable	$ 6,822	$ 1,914
Net profits interests revenue	$ 17,596	$ 8,714
General and administrative amounts payable	$ 85	$ 486
Total general and administrative expenses	$ 571	$ 2,905

5. Commitments and Contingencies

Our Partnership and the Operating Partnership are involved in legal and/or administrative proceedings arising in the ordinary course of their businesses, none of which have predictable outcomes and none of which are believed to have any significant effect on consolidated financial position, cash flows, or operating results.

6. Distribution To Holders of Common Units

During 2020 and during the first and second quarter of 2021, cash distributions were paid on 34,679,774 units. During the third and fourth quarter of 2021, cash distributions were paid on 35,404,774 units. Fourth quarter cash distributions are paid in February of the following calendar year to unitholders of record in January or February of such following year. The partnership agreement requires the next cash distribution to be paid by May 15, 2022.

7. Leases

The third amendment to our Office Lease was executed in April 2017 for a term of 129 months, beginning June 1, 2018 and expiring in 2029. At lease commencement, the Partnership concluded the Office Lease was an operating lease. Under the third amendment to the Office Lease, monthly rental payments range from $25,000 to $30,000 and the Partnership received lease incentives of $0.7 million.

Lease expense for the years ended December 31, 2021 and 2020 was as follows:

	In Thousands	
	2021	2020
Operating lease expense	$ 262	$ 262

Supplemental cash flow information related to leases was as follows:

	In Thousands	
	2021	2020
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from operating leases	$ 338	$ 332

Supplemental balance sheet information related to leases was as follows:

	2021	2020
Weighted-Average Remaining Lease Term (months)		
Operating lease	86	98
Weighted-Average Discount Rate		
Operating lease	5%	5%

Maturities of lease liabilities are as follows:

	In Thousands
	2021
2022	$ 344
2023	350
2024	356
2025	362
2026	368
Thereafter	817
Total lease payments	2,597
Less amount representing interest	(712)
Total lease obligation	$ 1,885

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

Supplemental Oil and Natural Gas Data
(Unaudited)

Oil and Natural Gas Reserve and Standardized Measure

The NPI represents a net profit overriding royalty interest in various properties owned by the Operating Partnership. The Royalty Properties consist of producing and nonproducing mineral, royalty, overriding royalty, net profits, and leasehold interests located in 582 counties and parishes in 26 states. Amounts set forth herein attributable to the NPI reflects our 96.97% net share. Although new activity has occurred on certain of the Royalty Properties, based on engineering studies available to date, no events have occurred since December 31, 2021 that would have a material effect on our estimated proved developed reserves.

In accordance with U.S. GAAP and Securities and Exchange Commission rules and regulations, the following information is presented with regard to the Royalty Properties and NPI oil and natural gas reserves, all of which are proved, developed, and located in the United States. These rules require inclusion as a supplement to the basic financial statements a standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves. The standardized measure, in management's opinion, should be examined with caution. The basis for these disclosures are petroleum engineers' reserve studies which contain estimates of quantities and rates of production of reserves. Revision of prior year estimates can have a significant impact on the results. Changes in production costs may result in significant revisions to previous estimates of proved reserves and their future value. Therefore, the standardized measure is not necessarily a best estimate of the fair value of oil and natural gas properties or of future net cash flows.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves. The Standardized Measure of Discounted Future Net Cash Flows reflects adjustments for fuel, shrinkage, and pipeline loss.

	Oil (mbbls)			Natural Gas (mmcf)		
	2021	2020	2019	2021	2020	2019
Estimated quantity, beginning of year	9,344	9,638	9,041	33,779	45,860	44,230
Revisions in previous estimates (1)	547	1,368	1,394	7,991	(1,853)	6,466
Purchase of minerals in place (2)	630	-	788	1,093	-	1,933
Sales of minerals in place (3)	-	(203)	-	-	(4,447)	-
Production	(1,346)	(1,459)	(1,585)	(4,964)	(5,781)	(6,769)
Estimated quantity, end of year	9,175	9,344	9,638	37,899	33,779	45,860

(1) Changes in oil reserves for the years ended December 31, 2021, 2020, and 2019 include upward revisions of 547 mbbls, 1,368, mbbls and 1,394 mbbls, respectively, predominately due to ongoing development on our Permian Basin and Bakken properties and well performance exceeding previous projections in various areas with 2020 and 2019 upward revisions partially offset by reductions in the estimated economic lives and future reserves of various properties in the Bakken due to declines in oil prices.

Changes in natural gas reserves for the years ended December 31, 2021, 2020, and 2019 include an upward revision of 7,991 mmcf in 2021 predominately due to ongoing development on our Permian Basin and Bakken properties and increases in the estimated economic lives and future reserves of properties in various areas due to increase in natural gas prices, a downward revision of 1,853 mmcf in 2020 primarily as a result of reductions in the estimated economic lives and future reserves of various properties in the Bakken, Barnett Shale and Fayetteville Shale due to declines in natural gas prices, partially offset by ongoing development on our Permian Basin and Bakken properties and well performance exceeding previous projections in various areas, and an upward revision of 6,466 mmcf in 2019 primarily as a result of increased Permian Basin and East Texas activity, partially offset by decreased activity in the Hugoton Field.

(2) On December 31, 2021, pursuant to a non-taxable contribution and exchange agreement with Gemini 5 Thirty, LP, a Texas limited partnership ("Gemini"), the Partnership acquired mineral and royalty interests representing approximately 4,600 net royalty acres located in 27 counties across New Mexico, Oklahoma, Texas and Wyoming. The acquisition represented 465 mbbls and 996 mmcf of 2021 purchases of minerals in place.

On June 30, 2021, pursuant to a contribution and exchange agreement with JSFM, LLC, a Wyoming limited liability company ("JSFM"), the Partnership acquired overriding royalty interests in the Bakken Trend totaling approximately 6,400 net royalty acres located in Dunn, McKenzie, McLean and Mountrail Counties, North Dakota. The acquisition represented 165 mbbls and 97 mmcf of 2021 purchases of minerals in place.

On March 29, 2019, pursuant to a Contribution and Exchange Agreement with H. Huffman & Co., A Limited Partnership, an Oklahoma limited partnership ("HHC"), The Buffalo Co., A Limited Partnership, an Oklahoma limited partnership ("TBC" and together with HHC, the "Acquired Entities"), Huffman Oil Co., L.L.C., an Oklahoma limited liability company, and the equity holders of the Acquired Entities, the Partnership acquired (i) a 96.97% net profits interest in certain working interests in various oil and gas properties owned by HHC, (ii) all of the minerals and royalty interests held by HHC, and (iii) all of the minerals and royalty interests held by TBC.

(3) During 2020, the Partnership and affiliates of its General Partner closed the divestitures of our Hugoton and HHC net profits interests. The Hugoton and HHC net profits interests properties represented 408 mbbls and 9,377 mmcf of 2019 end of year reserves.

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

Supplemental Oil and Natural Gas Data
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows
(Dollars in Thousands Except Where Noted)

	2021	2020	2019
Future estimated gross revenues	$ 602,130	$ 316,871	$ 452,992
Future estimated production costs	(34,002)	(17,373)	(25,542)
Future estimated net revenues	568,128	299,498	427,450
10% annual discount for estimated timing of cash flows	(298,661)	(162,666)	(218,616)
Standardized measure of discounted future estimated net cash flows	$ 269,467	$ 136,832	$ 208,834
Sales of oil and natural gas produced, net of production costs	$ (81,367)	$ (40,064)	$ (67,865)
Net changes in prices and production costs	139,009	(48,962)	(51,526)
Net change due to purchase of minerals in place	17,023	-	17,843
Net change due to sales of minerals in place	-	(10,260)	-
Revisions of previous quantity estimates	36,253	11,519	49,492
Accretion of discount	13,683	20,883	24,826
Change in production rate and other	8,034	(5,118)	(12,200)
Net change in standardized measure of discounted future estimated net cash flows	$ 132,635	$ (72,002)	$ (39,430)
Depletion of oil and natural gas properties (dollars per mcfe)	$ 0.80	$ 0.81	$ 0.81
Property acquisition costs	$ 40,770	$ -	$ 42,904
Average oil price per barrel (1)(2)	$ 59.23	$ 32.43	$ 44.38
Average natural gas price per mcf (1)	$ 2.83	$ 1.04	$ 1.72

(1) Includes Royalty and NPI prices combined by volumetric proportions.
(2) Includes oil and natural gas liquids prices combined by volumetric proportions.

Exhibit 21.1

Subsidiaries of Registrant

1. Dorchester Minerals Oklahoma LP, an Oklahoma limited partnership
2. Dorchester Minerals Oklahoma GP, Inc., an Oklahoma corporation
3. Maecenas Minerals LLP, a Texas limited liability partnership
4. Dorchester-Maecenas GP LLC, a Texas limited liability company
5. The Buffalo Co., A Limited Partnership, an Oklahoma limited partnership
6. DMLPTBC GP LLC, a Delaware limited liability company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 24, 2022 with respect to the consolidated financial statements included in the Annual Report of Dorchester Minerals, L.P. on Form 10-K for the year ended December 31, 2021. We consent to the incorporation by reference of said report in the Registration Statements of Dorchester Minerals, L.P. on Form S-3 (File No. 333-233220) and on Forms S-4 (File No. 333-231841 and File No. 333-256021).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 24, 2022

Exhibit 23.2

February 24, 2022

Dorchester Minerals, L.P.
3838 Oak Lawn Avenue, Suite 300
Dallas, Texas 75219-4541

Gentlemen:

LaRoche Petroleum Consultants, Ltd. does hereby consent to the incorporation by reference in the Registration Statement on Form S-3 and S-4 (No. 333-231841, No. 333-233220, and No. 333-256021) of Dorchester Minerals, L.P. of our estimated reserves included in the Annual Report dated February 24, 2022, for the year ended December 31, 2021, on Form 10-K including, without limitation, Exhibit 99.1 and 99.2, and to references to our firm included in this Annual Report.

LAROCHE PETROLEUM CONSULTANTS, LTD.
By LPC, Inc. General Partner

/s/ Joe A. Young

Joe A. Young, Vice President

2435 N. Central Expy, Suite 1500 ● Richardson, Texas 75080
Phone (214) 363-3337 ● Fax (214) 363-1608

Exhibit 31.1

CERTIFICATIONS

I, William Casey McManemin, certify that:

1. I have reviewed this annual report on Form 10-K of Dorchester Minerals, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer of
Dorchester Minerals Management GP LLC
The General Partner of Dorchester Minerals Management LP
The General Partner of Dorchester Minerals, L. P.

Date: February 24, 2022

Exhibit 31.2

I, Leslie Moriyama, certify that:

1. I have reviewed this annual report on Form 10-K of Dorchester Minerals, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Leslie Moriyama
Leslie Moriyama
Chief Financial Officer of
Dorchester Minerals Management GP LLC,
The General Partner of Dorchester Minerals Management LP
The General Partner of Dorchester Minerals, L.P.

Date: February 24, 2022

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the accompanying Annual Report of Dorchester Minerals, L.P., (the "Partnership") on Form 10-K for the period ended December 31, 2021 (the "Report”), each of the undersigned officers of Dorchester Minerals Management GP LLC, General Partner of Dorchester Minerals Management LP, General Partner of the Partnership, hereby certifies that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer

Date: February 24, 2022

/s/ Leslie Moriyama
Leslie Moriyama
Chief Financial Office

Date: February 24, 2022

Exhibit 99.1

January 31, 2022

Mr. Brad Ehrman
Dorchester Minerals, L.P.
3838 Oak Lawn, Suite 300
Dallas, Texas 75219-4541

Dear Mr. Ehrman:

At your request, LaRoche Petroleum Consultants, Ltd. (LPC) has estimated the proved developed producing reserves (PDP) and future net cash flow, as of December 31, 2021, to the Dorchester Minerals, L.P. (DMLP) royalty interest in certain properties located onshore in the United States. The work for this report was completed as of the date of this letter. This report was prepared to provide DMLP with U.S. Securities and Exchange Commission (SEC) compliant reserve estimates. It is our understanding that the properties evaluated by LPC comprise one hundred (100%) percent of DMLP's PDP reserves of which one hundred (100%) percent were evaluated on a net reserve basis. We believe the assumptions, data, methods, and procedures used in preparing this report, as set out below, are appropriate for the purpose of this report. This report has been prepared using constant prices and costs and conforms to our understanding of the SEC guidelines, reserves definitions, and applicable financial accounting rules.

We note that we have necessarily included composite projections of net oil and gas reserves for certain properties due to the limited information available to DMLP as a royalty interest owner and relatively small net reserves attributable to any specific property within the composite groups.

Summarized below are LPC's estimates of net reserves and future net cash flow. Future net cash flow is after deducting production and ad valorem taxes and operating expenses but before consideration of federal income taxes. The discounted cash flow values included in this report are intended to represent the time value of money and should not be construed to represent an estimate of fair market value. We estimate the net reserves and future net cash flow to the DMLP interest, as of December 31, 2021, to be:

	Net Reserves			Future Net Cash Flow (M$)	
Category	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Total	Present Worth at 10%
Proved Developed Producing	6,248	31,364	1,436	$ 509,661	$ 233,100

The oil reserves include crude oil and condensate. Oil and natural gas liquid (NGL) reserves are expressed in barrels which are equivalent to 42 United States gallons. Gas reserves are expressed in thousands of standard cubic feet (Mcf) at the contract temperature and pressure bases.

The estimated reserves and future net cash flow shown in this report are for proved developed producing reserves. No study was made to determine whether proved developed non-producing or proved undeveloped reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage.

Estimates of reserves were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserves in this report have been estimated using deterministic methods. The method or combination of methods utilized in the evaluation of each reservoir included consideration of the stage of development of the reservoir, quality and completeness of basic data, and production history. Recovery from various reservoirs and leases was estimated after consideration of the type of energy inherent in the reservoirs, the structural positions of the properties, and reservoir and well performance. In some instances, comparisons were made to similar properties where more complete data were available. We have used all methods and procedures that we considered necessary under the circumstances to prepare this report. We have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting rather than engineering or geoscience.

The estimated reserves and future net cash flow amounts in this report are related to hydrocarbon prices. Historical prices through December 2021 were used in the preparation of this report as required by SEC guidelines; however, actual future prices may vary significantly from the SEC prices. In addition, future changes in environmental and administrative regulations may significantly affect the ability of DMLP to produce oil and gas at the projected levels. Therefore, volumes of reserves actually recovered and amounts of cash flow actually received may differ significantly from the estimated quantities presented in this report.

Benchmark prices used in this report are based on the twelve-month, unweighted arithmetic average of the first day of the month price for the period January through December 2021. Gas prices are referenced to a Henry Hub price of $3.60 per MMBtu, as published in the Platts Gas Daily, and are adjusted for energy content, transportation fees, and regional price differentials. Oil and NGL prices are referenced to a West Texas Intermediate crude oil price of $66.56 per barrel at Cushing, Oklahoma, and are adjusted for gravity, crude quality, transportation fees, and regional price differentials. These reference prices are held constant in accordance with SEC guidelines. The weighted average prices after adjustments over the life of the properties are $64.26 per barrel for oil, $2.80 per Mcf for gas, and $37.95 per barrel for NGL.

The interests evaluated in this report consist of only royalty interests that are not burdened by lease operating costs and capital costs.

LPC has made no investigation of possible gas volume and value imbalances that may have resulted from the overdelivery or underdelivery to the DMLP interest. Our projections are based on the DMLP interest receiving its net revenue interest share of estimated future gross oil, gas, and NGL production.

Technical information necessary for the preparation of the reserve estimates herein was furnished by DMLP or was obtained from state regulatory agencies and commercially available data sources. No special tests were obtained to assist in the preparation of this report. For the purpose of this report, the individual well test and production data as reported by the above sources were accepted as represented together with all other factual data presented by DMLP including the extent and character of the interest evaluated.

LaRoche Petroleum Consultants, Ltd.

An on-site inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined by LPC. In addition, the costs associated with the continued operation of uneconomic properties are not reflected in the cash flows.

The evaluation of potential environmental liability from the operation and abandonment of the properties is beyond the scope of this report. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the projections presented herein.

The reserves included in this report are estimates only and should not be construed as exact quantities. They may or may not be recovered; if recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. These estimates should be accepted with the understanding that future development, production history, changes in regulations, product prices, and operating expenses would probably cause us to make revisions in subsequent evaluations. A portion of these reserves are for producing wells that lack sufficient production history to utilize performance-related reserve estimates. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogies to similar production. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. It may be necessary to revise these estimates up or down in the future as additional performance data become available. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geological data; therefore, our conclusions represent informed professional judgments only, not statements of fact.

The results of our third-party study were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by DMLP.

DMLP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, DMLP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of DMLP of the references to our name as well as to the references to our third-party report for DMLP which appears in the December 31, 2021 annual report on Form 10-K and/or 10-K/A of DMLP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by DMLP.

We have provided DMLP with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by DMLP and the original signed report letter, the original signed report letter shall control and supersede the digital version.

LaRoche Petroleum Consultants, Ltd.

The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers. The technical person primarily responsible for overseeing the preparation of reserve estimates herein is Joe A. Young. Mr. Young is a Licensed Professional Engineer in the State of Texas who has 40 years of engineering experience in the oil and gas industry and has prepared and overseen preparation of reports for public filings for LPC for the past 25 years. LPC is an independent firm of petroleum engineers, geologists, and geophysicists; and is not employed on a contingent basis. Data pertinent to this report are maintained on file in our office.

Very truly yours,

LaRoche Petroleum Consultants, Ltd.
State of Texas Registration Number F-1360
By LPC, Inc. General Partner

Joe A. Young, Vice President
Licensed Professional Engineer
State of Texas No. 62866

JAY:pt
21-914 DMLP

LAROCHE Petroleum Consultants

January 30, 2022

Mr. Brad Ehrman
Dorchester Minerals Operating LP
3838 Oak Lawn, Suite 300
Dallas, Texas 75219-4541

Dear Mr. Ehrman:

At your request, LaRoche Petroleum Consultants, Ltd. (LPC) has estimated the proved developed producing reserves (PDP) and future net cash flow, as of December 31, 2021, to the Dorchester Minerals Operating LP (DMO) interest in certain properties located onshore in the United States. The work for this report was completed as of the date of this letter. This report was prepared to provide DMO with U.S. Securities and Exchange Commission (SEC) compliant reserve estimates. It is our understanding that the properties evaluated by LPC comprise one hundred (100%) percent of DMO's PDP reserves. We believe the assumptions, data, methods, and procedures used in preparing this report, as set out below, are appropriate for the purpose of this report. This report has been prepared using constant prices and costs and conforms to our understanding of the SEC guidelines, reserves definitions, and applicable financial accounting rules.

We note that we have necessarily included composite projections of net oil and gas reserves for certain properties due to the limited information available to DMO and relatively small net reserves attributable to any specific property within the composite groups.

Summarized below are LPC's estimates of net reserves and future net cash flow. Future net cash flow is after deducting production and ad valorem taxes and operating expenses but before consideration of federal income taxes. The discounted cash flow values included in this report are intended to represent the time value of money and should not be construed to represent an estimate of fair market value. We estimate the net reserves and future net cash flow to the DMO interest, as of December 31, 2021, to be:

	Net Reserves			Future Net Cash Flow (M$)	
Category	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Total	Present Worth at 10%
Proved Developed Producing	1,231	6,739	307	$ 60,294	$ 37,503

The oil reserves include crude oil and condensate. Oil and natural gas liquid (NGL) reserves are expressed in barrels which are equivalent to 42 United States gallons. Gas reserves are expressed in thousands of standard cubic feet (Mcf) at the contract temperature and pressure bases.

The estimated reserves and future net cash flow shown in this report are for proved developed producing reserves. No study was made to determine whether proved developed non-producing or proved undeveloped reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage.

Estimates of reserves were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserves in this report have been estimated using deterministic methods. The method or combination of methods utilized in the evaluation of each reservoir included consideration of the stage of development of the reservoir, quality and completeness of basic data, and production history. Recovery from various reservoirs and leases was estimated after consideration of the type of energy inherent in the reservoirs, the structural positions of the properties, and reservoir and well performance. In some instances, comparisons were made to similar properties where more complete data were available. We have used all methods and procedures that we considered necessary under the circumstances to prepare this report. We have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting rather than engineering or geoscience.

The estimated reserves and future net cash flow amounts in this report are related to hydrocarbon prices. Historical prices through December 2021 were used in the preparation of this report as required by SEC guidelines; however, actual future prices may vary significantly from the SEC prices. In addition, future changes in environmental and administrative regulations may significantly affect the ability of DMO to produce oil and gas at the projected levels. Therefore, volumes of reserves actually recovered and amounts of cash flow actually received may differ significantly from the estimated quantities presented in this report.

Benchmark prices used in this report are based on the twelve-month, unweighted arithmetic average of the first day of the month price for the period January through December 2021. Gas prices are referenced to a Henry Hub price of $3.60 per MMBtu, as published in the Platts Gas Daily, and are adjusted for energy content, transportation fees, and regional price differentials. Oil and NGL prices are referenced to a West Texas Intermediate crude oil price of $66.56 per barrel at Cushing, Oklahoma, and are adjusted for gravity, crude quality, transportation fees, and regional price differentials. These reference prices are held constant in accordance with SEC guidelines. The weighted average prices after adjustments over the life of the properties are $63.40 per barrel for oil, $2.96 per Mcf for gas, and $39.67 per barrel for NGL.

Lease and well operating expenses are based on data obtained from DMO. Leases and wells operated by others include all direct expenses as well as general and administrative overhead costs allowed under the specific joint operating agreements. Lease and well operating costs are held constant in accordance with SEC guidelines.

Estimates of the cost to plug and abandon the wells net of salvage value are included and scheduled at the end of the economic life of individual properties. These costs are also held constant.

LPC has made no investigation of possible gas volume and value imbalances that may have resulted from the overdelivery or underdelivery to the DMO interest. Our projections are based on the DMO interest receiving its net revenue interest share of estimated future gross oil, gas, and NGL production.

Technical information necessary for the preparation of the reserve estimates herein was furnished by DMO or was obtained from state regulatory agencies and commercially available data sources. No special tests were obtained to assist in the preparation of this report. For the purpose of this report, the individual well test and production data as reported by the above sources were accepted as represented together with all other factual data presented by DMO including the extent and character of the interest evaluated.

LaRoche Petroleum Consultants, Ltd.

An on-site inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined by LPC. In addition, the costs associated with the continued operation of uneconomic properties are not reflected in the cash flows.

The evaluation of potential environmental liability from the operation and abandonment of the properties is beyond the scope of this report. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the projections presented herein.

The reserves included in this report are estimates only and should not be construed as exact quantities. They may or may not be recovered; if recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. These estimates should be accepted with the understanding that future development, production history, changes in regulations, product prices, and operating expenses would probably cause us to make revisions in subsequent evaluations. A portion of these reserves are for producing wells that lack sufficient production history to utilize performance-related reserve estimates. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogies to similar production. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. It may be necessary to revise these estimates up or down in the future as additional performance data become available. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geological data; therefore, our conclusions represent informed professional judgments only, not statements of fact.

The results of our third-party study were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by DMO.

DMO makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, DMO has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of DMO of the references to our name as well as to the references to our third-party report for DMO which appears in the December 31, 2021 annual report on Form 10-K and/or 10-K/A of DMO. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by DMO.

We have provided DMO with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by DMO and the original signed report letter, the original signed report letter shall control and supersede the digital version.

LaRoche Petroleum Consultants, Ltd.

The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers. The technical person primarily responsible for overseeing the preparation of reserve estimates herein is Joe A. Young. Mr. Young is a Licensed Professional Engineer in the State of Texas who has 40 years of engineering experience in the oil and gas industry and has prepared and overseen preparation of reports for public filings for LPC for the past 25 years. LPC is an independent firm of petroleum engineers, geologists, and geophysicists; and is not employed on a contingent basis. Data pertinent to this report are maintained on file in our office.

Very truly yours,

LaRoche Petroleum Consultants, Ltd.
State of Texas Registration Number F-1360
By LPC, Inc. General Partner

Joe A. Young, Vice President
Licensed Professional Engineer
State of Texas No. 62866

JAY:pt
21-914 DMO