Risk Factors Comparison 2025-02-28 to 2024-03-07 Form: 10-K

Legend: **New Text** ~~Removed Text~~ Unchanged Text Moved Text Section

We are subject to a variety of risks and uncertainties, including risks related to our business, risks related to our indebtedness, risks related to our common units and certain general risks, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. Risks that we deem material are described under " Risk Factors " in Item 1A of this report. These risks include, but are not limited to, the following: Risks Related to Our Business • Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves. In addition, our debt agreements and our partnership agreement place restrictions on our ability to pay, and in some cases raise, the quarterly distribution under certain circumstances. • Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects. • Global pandemics ~~, including the COVID- 19 pandemic,~~ have in the past and may continue to adversely affect our business. • Prices for both metallurgical and thermal coal are volatile and depend on a number of factors beyond our control. Declines in prices could have a material adverse effect on our business and **results of operations. • Changes to trade regulations, including trade restrictions, sanctions, tariffs, or duties, could significantly harm our** results of operations. • Prices for soda ash are volatile. Any substantial or extended decline in soda ash prices could have an adverse effect on Sisecam Wyoming' s ability to continue to make distributions to us. • We derive a large percentage of our revenues and other income from a small number of coal lessees. • Bankruptcies in the coal industry, and / or the idling or closure of mines on our properties could have a material adverse effect on our business and results of operations. • Mining operations are subject to operating risks that could result in lower revenues to us. • The adoption of climate change legislation and regulations restricting emissions of greenhouse gases and other hazardous air pollutants have resulted in changes in fuel consumption patterns by electric power generators and a corresponding decrease in coal production by our lessees and reduced coal- related revenues. • Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are also resulting in unfavorable lending and investment policies by institutions and insurance companies which could significantly affect our ability to raise capital or maintain current insurance levels. • Increased attention to climate change, environmental, social and governance (" ESG") matters and conservation measures may adversely impact our business. • In addition to climate change and other Clean Air Act legislation, our businesses are subject to numerous other federal, state and local laws and regulations that may limit production from our properties and our profitability. **Thus, any changes in environmental laws and regulations or reinterpretations of enforcement policies, or in presidential administrations, that result in more stringent or costly obligations could adversely affect our performance.** • If our lessees do not manage their operations well, their production volumes and our royalty revenues could decrease. • We have limited approval rights with respect to the management of our Sisecam Wyoming soda ash joint venture, including with respect to cash distributions and capital expenditures. In addition, we are exposed to operating risks that we do not experience in the royalty business through our soda ash joint venture and through our ownership of certain coal transportation assets. • Sisecam Wyoming' s **reserve** ~~deca stockpiles will substantially deplete by 2024,~~ and ~~its production rates will decline if~~ **resource data are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future, which could materially and adversely affect the quantities and value of** Sisecam Wyoming **' s reserves and resources** ~~does not make further investments or otherwise execute on one or more initiatives to prevent such decline~~ . • Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal, soda ash and other minerals from our properties. • Our lessees could satisfy obligations to their customers with minerals from properties other than ours, depriving us of the ability to receive amounts in excess of minimum royalty payments. • A lessee may incorrectly report royalty revenues, which might not be identified by our lessee audit process or our mine inspection process or, if identified, might be identified in a subsequent period. Risks Related to Our Structure • Unitholders may not be able to remove our general partner even if they wish to do so. • ~~The preferred units are senior in right of distributions and liquidation and upon conversion, would result in the issuance of additional common units in the future, which could result in substantial dilution of our common unitholders' ownership interests. •~~ We may issue additional common units or ~~preferred units~~ **other equity securities** without common unitholder approval, which ~~would~~ **could** dilute a unitholder' s existing ownership interests. • Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price. • Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders. • Conflicts of interest could arise among our general partner and us or the unitholders. • The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements. • Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business. Tax Risks to Common Unitholders • Our tax treatment depends on our status as a partnership for U. S. federal income tax purposes as well as our not being subject to a material amount of entity- level taxation by individual states. If the Internal Revenue Service (" IRS") were to treat us as a corporation for U. S. federal income tax purposes or we were to become subject to material additional amounts of entity- level taxation for state tax purposes, then our cash available for distribution to unitholders would be substantially reduced. • The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis. • Certain U. S. federal income tax preferences currently available with respect to coal exploration and development may be eliminated as a result of future legislation. • Our unitholders are required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities. • We may engage in transactions to reduce our indebtedness and manage our liquidity that generate taxable income (including income and gain from the sale of properties and cancellation of indebtedness income) allocable to our unitholders, and income tax liabilities arising therefrom may exceed any distributions made with respect to their units. • If the IRS contests the U. S. federal income tax positions we take, the market for our units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders. • If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced. • Tax gain or loss on the disposition of our common units could be more or less than expected. • Our unitholders may be subject to limitation on their ability to deduct interest expense incurred by us. • Tax- exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them. • Non- U. S. unitholders will be subject to U. S. federal income taxes and withholding **from their distributions and sale proceeds** with respect to their income and gain from owning our units. • We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units. • We have adopted certain valuation methodologies in determining a unitholder' s allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units. • We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders. • A unitholder whose units are the subject of a securities loan (e. g., a loan to a" short seller" to cover a short sale of units) may be considered as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. • As a result of investing in our units, our unitholders are likely subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property. General ~~Risks~~ **Risk Factors** • Our business is subject to cybersecurity risks. Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may have an adverse effect on our business, financial condition, results of operations ~~,~~ and cash flows. ivPART I As used in this Annual Report on Form 10- K, unless the context otherwise requires:" we,"" our,"" us" and the" Partnership" refer to Natural Resource Partners L. P. and, where the context requires, our subsidiaries. References to" NRP" and" Natural Resource Partners" refer to Natural Resource Partners L. P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L. P.' s subsidiaries. References to" Opco" refer to NRP (Operating) LLC, a wholly owned subsidiary of NRP, and its subsidiaries ~~. NRP Finance Corporation (" NRP Finance") is a wholly owned subsidiary of NRP and was a co- issuer with NRP on the 9. 125 % senior notes due 2025 (the" 2025 Senior Notes")~~ . ITEMS 1. AND 2. BUSINESS AND PROPERTIES Partnership Structure and Management We are a publicly traded Delaware limited partnership formed in 2002. We own, manage and lease a diversified portfolio of mineral properties in the United States, including interests in coal and other natural resources and own a non- controlling 49 % interest in Sisecam Wyoming LLC (" Sisecam Wyoming"), a trona ore mining and soda ash production business. Our business is organized into two operating segments: Mineral Rights — consists of approximately 13 million acres of mineral interests and other subsurface rights across the United States. If combined in a single tract, our ownership would cover roughly 20, 000 square miles. Our ownership provides critical inputs for the manufacturing of steel, electricity and basic building materials, as well as opportunities for carbon sequestration and renewable energy. We are working to strategically redefine our business as a key player in the transitional energy economy in the years to come. Soda Ash — consists of our 49 % non- controlling equity interest in Sisecam Wyoming, a trona ore mining and soda ash production business located in the Green River Basin of Wyoming. Sisecam Wyoming mines trona and processes it into soda ash that is sold both domestically and internationally into the glass and chemicals industries. Our operations are conducted through Opco and our operating assets are owned by our subsidiaries. NRP (GP) LP, our general partner (the" general partner" or" NRP GP"), has sole responsibility for conducting our business and for managing our operations. Because our general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC (the" managing general partner"), conducts its business and operations and the board of directors and officers of GP Natural Resource Partners LLC make decisions on our behalf. Robertson Coal Management LLC (" RCM"), a limited liability company indirectly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. **All members** ~~Pursuant to the Board Representation and Observation Rights Agreement entered into in 2017 with certain entities controlled by funds affiliated with Blackstone Inc. (collectively referred to as" Blackstone") and affiliates~~ of ~~GoldenTree Asset Management LP (collectively referred to as" GoldenTree"), Blackstone was entitled to appoint one person to~~ the board of directors of ~~GP Natural Resource~~ **the managing general** ~~Partners~~ **partner** ~~LLC~~ (the" Board of Directors") ~~. However, in 2023, we repurchased all of Blackstone' s preferred units, which were subsequently retired and no longer remain outstanding, and all rights of Blackstone related thereto ceased as a result. In connection with the repurchase, Blackstone' s board designee resigned from the Board of Directors and all members of the Board of Directors~~ are ~~now~~ appointed by RCM. The senior executives and other officers who manage NRP are employees of Western Pocahontas Properties Limited Partnership or Quintana Minerals Corporation, which are companies controlled by Mr. Robertson, Jr. These officers allocate varying percentages of their time to managing our operations. Neither our general partner, GP Natural Resource Partners LLC, nor any of their affiliates receive any management fee or other compensation in connection with the management of our business, but they are entitled to be reimbursed for all direct and indirect expenses incurred on our behalf. We have regional offices through which we conduct our operations, the largest of which is located at ~~5260~~ **175** Irwin Road, Huntington, West Virginia 25705 and the telephone number is (304) 522- 5757. Our principal executive office is located at 1415 Louisiana Street, Suite 3325, Houston, Texas 77002 and our telephone number is (713) 751- 7507. Segment and Geographic Information The amount of ~~2023~~ **2024** revenues and other income from our two operating segments is shown below. For additional business segment information, please see" Item 7. Management' s Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations" and" Item 8. Financial Statements and Supplementary Data — Note 7. Segment Information" in this Annual Report on Form 10- K, which are both incorporated herein by reference. (In thousands) Amount % of Total Mineral Rights $ ~~296~~ **249** , ~~612~~ **872** % Soda Ash ~~73~~ **18** , ~~397~~ **135** % Total $ ~~370~~ **268** , ~~009~~ **007** % The following map shows the approximate geographic distribution of our ownership footprint: Mineral Rights Segment We do not mine, drill or produce minerals. Instead, we lease our acreage to companies engaged in the extraction of minerals in exchange for the payment of royalties and various other fees. The royalties we receive are generally a percentage of the gross revenue received by our lessees. The royalties we receive are typically supported by a floor price and minimum payment obligation that protect us during significant price or demand declines. The majority of our Mineral Rights segment revenues come from royalties related to the sale of coal from our properties. Our coal is primarily located in the Appalachia Basin, the Illinois Basin and the Northern Powder River Basin in the United States. We lease our coal to experienced mine operators under long- term leases. Approximately two- thirds of our royalty- based leases have initial terms of five to 40 years, with substantially all lessees having the option to extend the lease for additional terms. Leases include the right to renegotiate royalties and minimum payments for the additional terms. We also own and manage coal- related transportation and processing assets in the Illinois Basin that generate additional revenues generally based on throughput or rents. We also own oil and gas, industrial minerals and aggregates that generate a portion of the Mineral Rights segment revenues. Additional Mineral Rights segment revenues come from carbon neutral initiatives such the sale of carbon offset credits from ~~our~~ forestlands, potential sub- surface carbon dioxide sequestration in our pore space and opportunities to generate geothermal energy from our ownership. Under our standard royalty lease, we grant the operators the right to mine and sell our minerals in exchange for royalty payments based on the greater of a percentage of the ~~sale~~ **sales** price or fixed royalty per ton of minerals mined and sold. Lessees calculate royalty payments due to us and are required to report tons of minerals mined and sold as well as the sales prices of the extracted minerals. Therefore, to a great extent, amounts reported as royalty revenues are based upon the reports of our lessees. We periodically audit this information by examining certain records and internal reports of our lessees and we perform periodic mine inspections to verify that the information that our lessees have submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property. In addition to their royalty obligations, our lessees are often subject to minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Minimum payments are usually credited against future royalties that are earned as minerals are produced. In certain leases, the lessee is time limited on the period available for recouping minimum payments and such time is unlimited on other leases. Because we do not operate, our royalty business does not bear ordinary operating costs and has limited direct exposure to environmental, permitting and labor risks. Our lessees, as operators, are subject to environmental laws, permitting requirements and other regulations adopted by various governmental authorities. In addition, the lessees generally bear all labor- related risks, including retiree health care costs, black lung benefits and workers' compensation costs associated with operating the mines on our coal and aggregates properties. We pay property taxes on our properties, which are largely reimbursed by our lessees pursuant to the terms of the various lease agreements. The SEC amended the property disclosure requirements for registrants with significant mining activities, effective for the fiscal year 2021, with new rules which we comply with in this Annual Report on Form 10- K. The rules contain exceptions that allow royalty companies, such as NRP, to omit information that they lack access to and cannot obtain without incurring an unreasonable burden or expense. As a royalty company, we do not have access to the information required to prepare the technical reports used to determine reserves under the rules, and we are not able to obtain such information without unreasonable burden or expense. The rules require that reserve estimates be based on and **that** disclosures include technical reports prepared using extensive mine- specific geological and engineering data, as well as market and cost assumptions that we as a mineral owner do not have, including, but not limited to a) site infrastructure costs; b) processing plant costs; c) detailed analysis of environmental compliance and permitting requirements; d) detailed baseline studies with impact assessment; and e) detailed tailings disposal, reclamation and mitigation plans. Our leases do not require the operators of our material properties to prepare technical report summaries or permit us the access and information sufficient to prepare our own technical report summaries under the rules. As a result, we are relying on the royalty company exceptions and have ceased to report coal and other hard mineral reserves. In addition to summary information about our overall portfolio of mineral rights, this section provides detailed information about four properties in our Mineral Rights segment. These properties were determined to be material to our business based on historical revenue compared to our Mineral Rights segment considered as a whole. These four properties are: 1) Alpha- CAPP (VA), 2) Oak Grove, 3) Williamson ~~,~~ and 4) Hillsboro. We have also included a description of other significant properties, which have had lower revenues historically than our material properties but are important to our business. Metallurgical Coal Metallurgical (" Met ") coal is used to fuel blast furnaces that forge steel and is the primary driver of our long- term cash flows. Met coal is a high- quality, cleaner coal that generates exceptionally high temperatures when burned and is an essential element in the steel manufacturing process. Metallurgical coal is a finite and declining resource, particularly in industrialized nations. We believe the indispensable role met coal plays in manufacturing steel combined with the increasing scarcity of the resource will provide support for this portion of our business for decades to come. Our metallurgical coal is located in the Northern, Central and Southern Appalachian regions of the United States. Thermal Coal Thermal coal, sometimes referred to as steam coal, is used in the production of electricity. The amount of thermal coal produced in the United States has been steadily falling over the last decade as energy providers shift from coal- fired plants to natural gas- fired facilities, and to a lesser extent, alternative energy sources such as geothermal, wind and solar. We believe the long- term secular decline experienced by thermal coal **in the United States** over the last decade will continue. That fact, combined with the long-term strength of our metallurgical business and the carbon neutral initiatives we discuss below, will result in thermal coal becoming a diminishing contributor to NRP in years to come. The vast majority of our thermal **coal** sales are located in Illinois and its operations are some of the most cost- efficient mines east of the Mississippi River. The remainder of our thermal coal is located in Montana, the Gulf Coast and Appalachia. Coal Production Information The following tables present the type of coal sales volumes by major coal region for the years ended December 31, **2024,** 2023 ~~, and~~ **and** 2022 ~~and 2021~~ : For the Year Ended December 31, ~~2023~~ **2024** Type of Coal (Tons in thousands) Thermal Metallurgical Total Appalachia Basin Northern 1, ~~145~~ **031** Central 1, ~~418~~ **782** 12, ~~509~~ **355 14,** ~~13~~ **137** ~~, 927~~ Southern — 2, ~~670~~ **661** 2, ~~670~~ **661** Total Appalachia Basin 2, ~~212~~ **342** 15, ~~530~~ **487** 17, ~~742~~ **829** Illinois Basin ~~8~~ **5** , ~~119~~ **723** — ~~8~~ **5** , ~~119~~ **723** Northern Powder River Basin ~~4~~ **2** , ~~589~~ **826** — ~~4~~ **2** , ~~589~~ **826** Gulf Coast 1, ~~477~~ **342** — 1, ~~477~~ **342** Total ~~16~~ **12** , ~~397~~ **233** 15, **487** ~~530 31, 927~~ **27, 720** For the Year Ended December 31, ~~2022~~ **2023** Type of Coal (Tons in thousands) Thermal Metallurgical Total Appalachia Basin Northern 1, **145** ~~166 1, 696~~ Central 1, ~~186~~ **418** 12, ~~460~~ **509** 13, ~~646~~ **927** Southern ~~1~~ **— 2** , ~~691 1~~ **670 2** , ~~784~~ **670** Total Appalachia Basin 2, ~~445 14~~ **212 15** , ~~681~~ **530** 17, ~~126~~ **742** Illinois Basin **8,** ~~11~~ **119** ~~, 135~~ — **8,** ~~11~~ **119** ~~, 135~~ Northern Powder River Basin 4, ~~288~~ **589** — 4, ~~288~~ **589** Gulf Coast **1, 477** — **1, 477** Total ~~18~~ **16** , ~~253 14~~ **397 15** , ~~681 32~~ **530 31** , ~~934~~ **927** For the Year Ended December 31, ~~2021~~ **2022** Type of Coal (Tons in thousands) Thermal Metallurgical Total Appalachia Basin Northern 1, ~~335~~ **166 1, 696** Central 1, **186** ~~140 11, 139~~ 12, ~~279~~ **460 13, 646** Southern 1, ~~452~~ **691** 1, ~~571~~ **784** Total Appalachia Basin ~~1~~ **2** , ~~977 13~~ **445 14** , ~~208 15~~ **681 17** , ~~185~~ **126** Illinois Basin ~~9~~ **11** , ~~388~~ **135** — ~~9~~ **11** , ~~388~~ **135** Northern Powder River Basin ~~3~~ **4** , ~~151~~ **288** — ~~3~~ **4** , ~~151~~ **288** Gulf Coast **—** Total **18, 253** 14, ~~571 13~~ **681 32** , **934** ~~208 27, 779~~ Major Coal Producing Properties The following table provides a summary of our significant coal royalty properties for ~~2023~~ **2024** and is followed by additional information for each property: Region Property / Lease Name Operator ~~(s)~~ Coal Type Appalachia Basin Central Alpha- CAPP (VA) Alpha Metallurgical Resources Inc. Met Central Kepler Alpha Metallurgical Resources Inc. Met Central **Marfork Alpha Metallurgical Resources Inc. Met Central Kingston Alpha Metallurgical Resources Inc. Met Central** Elk Creek Ramaco Royalty Company, LLC Met ~~Central Coal Mountain ECP Met~~ Southern Oak Grove **Alabama Kanu** ~~Hatfield Metallurgical Coal~~ Holdings, LLC Met Illinois Basin Williamson Foresight Energy Resources LLC Thermal Illinois Basin Hillsboro Foresight Energy Resources LLC Thermal Northern Powder River Basin Western Energy ~~Rosebud~~ **Westmoreland** Mining ~~,~~ LLC Thermal Appalachia Basin — Central Appalachia Alpha- CAPP (VA). The Alpha- CAPP (VA) property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. Substantially all of the tons sold from this property in ~~2023~~ **2024** were metallurgical coal. We lease this property to subsidiaries of Alpha Metallurgical Resources Inc. (" Alpha") and previously leased it to subsidiaries of Contura Energy, Inc. The current lease with Alpha expires at the end of 2028 and will automatically renew unless otherwise notified. We receive payments based on the greater of a percentage of the sale price or fixed royalty per ton of coal mined and sold. In addition to the royalty obligations, this lease is subject to minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Minimum payments are credited against future royalties that are earned as minerals are produced and the lessee is time limited on the period available for recouping minimum payments. Production comes from underground room and pillar and surface mines and is trucked to one of two preparation plants. Coal is shipped via the CSX and Norfolk Southern railroads to domestic and export metallurgical customers. The book value of this property was $ ~~46~~ **44** . ~~3~~ **0** million at December 31, ~~2023~~ **2024** . Below is a map of our Alpha- CAPP (VA) property: **Kepler. The Kepler property is located in Wyoming County, West Virginia. Substantially all of the coal sold from this property in 2024 was metallurgical coal. We lease this property to a subsidiary of Alpha. Metallurgical coal is produced from underground mines and transported by belt or truck to the preparation plant on the property. Coal is shipped via the Norfolk Southern railroad to export metallurgical customers. Marfork. The Marfork property is located in Boone and Raleigh Counties, West Virginia. Substantially all of the coal sold from this property in 2024 was metallurgical coal. We lease this property to a subsidiary of Alpha. Metallurgical coal is produced from underground mines and transported by belt or truck to the preparation plant on the property. Coal is shipped via the CSX railroad to both domestic and export metallurgical customers. Kingston. The Kingston property is located in Fayette and Raleigh Counties, West Virginia. Substantially all of the coal sold from this property in 2024 was metallurgical coal. We lease this property to a subsidiary of Alpha. Metallurgical coal is produced from surface and underground mines and transported by belt or truck to nearby preparation plants, including the Marfork complex. Coal is shipped via the CSX and Norfolk Southern railroads to both domestic and export metallurgical customers.** Elk Creek. The Elk Creek property is located in Logan and Wyoming Counties, West Virginia. **Substantially all of the coal sold from this property in 2024 was metallurgical coal.** We lease this property to Ramaco Resources, Inc. Metallurgical coal is produced from surface and underground mines and is transported by belt and truck to a preparation plant on the property. Coal is shipped via the CSX railroad to both domestic and ~~export metallurgical customers. Coal Mountain. The Coal Mountain property is located in Wyoming County, West Virginia. We lease this property to ECP. Metallurgical coal is produced from a multi- seam surface mine and coal is transported by truck to a preparation plant on the property. Coal is shipped via the Norfolk Southern railroad to both domestic and export metallurgical customers. Kepler. The Kepler property is located in Wyoming County, West Virginia. Substantially all of the coal sold from this property in 2023 was metallurgical coal. We lease this property to a subsidiary of Alpha. Coal is produced from underground mines and transported by belt or truck to the preparation plant on the property. Coal is shipped via the Norfolk Southern railroad to~~ export metallurgical customers. Appalachia Basin — Southern Appalachia Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. We currently lease this property to a subsidiary of **Alabama Kanu Holdings, LLC (" Alabama Kanu"). Previous operators of this property were** Hatfield Metallurgical Coal Holdings, LLC **,** ~~(" Hatfield Metallurgical"). Previous operators of this property were~~ Murray Metallurgical Coal Holdings LLC, Mission Coal, LLC, and Seneca Resources, LLC. The current lease with ~~Hatfield Metallurgical~~ **Alabama Kanu** expires in ~~2024~~ **2029** and will automatically renew unless otherwise notified. We receive payments based on the greater of a percentage of the sale price or fixed royalty per ton of coal mined and sold. In addition to the royalty obligations, this lease is subject to minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Minimum payments are credited against future royalties that are earned as minerals are produced and the lessee is time limited on the period available for recouping minimum payments. Metallurgical coal production comes from a longwall mine and is transported by beltline to a preparation plant. Metallurgical products are then shipped via railroad and barge to **primarily** ~~both domestic and~~ export customers **but can be shipped to domestic customers as well** . The book value of this property was $ 3. ~~5~~ **0** million at December 31, ~~2023~~ **2024** . Below is a map of our Oak Grove property: Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. This property is under leases to Williamson Energy, a subsidiary of Foresight Energy Resources LLC (" Foresight"). The current leases expire in 2026 and 2033 and will automatically renew unless otherwise notified. We receive payments based on the greater of a percentage of the sale price or fixed royalty per ton of coal mined and sold. In addition to the royalty obligations, these leases are subject to minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Minimum payments are credited against future royalties that are earned as minerals are produced and the lessee is time limited on the period available for recouping minimum payments. Thermal coal production comes from a longwall mine. Coal is shipped primarily via the Canadian National railroad to export customers. The book value of this property was $ ~~37~~ **34** . ~~0~~ **4** million at December 31, ~~2023~~ **2024** . Below is a map of our Williamson property: Hillsboro. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. This property is under lease to Hillsboro Energy, a subsidiary of Foresight. The current lease expires in 2033 and will automatically renew unless otherwise notified. We receive payments based on the greater of a percentage of the sale price or fixed royalty per ton of coal mined and sold. In addition to the royalty obligations, this lease is subject to non- recoupable minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Thermal coal production comes from a longwall mine. Coal is shipped by rail via either the Union Pacific, Norfolk Southern or Canadian National railroads, or by barges to domestic ~~utilities~~ **utility** customers. The book value of this property was $ ~~209~~ **203** . ~~3~~ **9** million at December 31, ~~2023~~ **2024** . Below is a map of our Hillsboro property: In addition to these properties, we own loadout and other transportation assets at the Williamson mine and at the Macoupin and Sugar Camp mines, which are also operated by Foresight. See" — Coal Transportation and Processing Assets" below for additional information on these assets. Production at the Foresight Macoupin mine was temporarily ceased in March 2020 **and remains in temporary cessation of production** . Foresight is no longer obligated to make royalty, transportation fee, or quarterly minimum payments to us under the Macoupin coal mining lease and transportation agreements. Foresight will instead pay an annual Macoupin fee of $ 2. 0 million to NRP each year through 2026. Foresight also forfeited its right to recoup all previously paid but unrecouped minimum payments with respect to the Macoupin mine. At all times that the Macoupin mine remains in temporary cessation of production, Foresight will take reasonable actions to preserve, protect, and store the equipment, infrastructure, and property located at the mine. Beginning January 1, 2027, we may at any time elect to cause Foresight to transfer the Macoupin mine and all associated equipment and permits to us for no consideration. If we make this election, we will assume all liabilities associated with the Macoupin mine. Also beginning January 1, 2027, Foresight may at any time elect to offer to sell the Macoupin assets to us for $ 1. 00. If we accept Foresight' s offer, we will assume all liabilities associated with the Macoupin mine. If we do not accept Foresight' s offer, Foresight may proceed to permanently seal the Macoupin mine and conduct all reclamation activities. To the extent the elections described above are not made, Foresight will continue to pay the annual $ 2. 0 million fee to NRP each year that the mine remains in temporary cessation of production. In addition, Foresight may determine at any time to recommence operations at the Macoupin mine, at which time we and Foresight will negotiate in good faith to enter into new coal mining lease and transportation agreements applicable to the Macoupin mine. Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. We lease this property to a subsidiary of Rosebud Mining, LLC. Thermal coal is produced by surface dragline mining methods. Coal is transported by either truck or beltline to the Colstrip generation station located at the mine mouth. We own transportation and processing infrastructure related to certain of our coal properties, including loadout and other transportation assets at Foresight' s Williamson mine in the Illinois Basin, for which we collect throughput fees or rents. We lease our Williamson transportation and processing infrastructure to a subsidiary of Foresight and are responsible for operating and maintaining the transportation and processing assets at the Williamson mine that we subcontract to a subsidiary of Foresight. In addition, we own rail loadout and associated infrastructure at the Sugar Camp mine, an Illinois Basin mine also operated by a subsidiary of Foresight. While we own coal at the Williamson mine, we do not own coal at the Sugar Camp mine. The infrastructure at the Sugar Camp mine is leased to a subsidiary of Foresight and we collect minimums and throughput fees. We recorded $ ~~14~~ **10** . 9 million in revenue related to our coal transportation and processing assets during the year ended December 31, ~~2023~~ **2024** . We also own transportation and processing infrastructure, including loadout and other transportation assets at Foresight' s Macoupin mine. As previously mentioned, the Macoupin mine was temporarily ceased in March 2020 and Foresight is no longer obligated to make transportation fee payments to us under the transportation agreements. Oil and Gas / Industrial Minerals / Construction Aggregates Our oil and gas properties are predominately located in Louisiana and during ~~2023~~ **2024** , we received $ ~~7~~ **8** . ~~4~~ **6** million in oil and gas royalty revenues. Our various industrial mineral and construction aggregates properties are located across the United States and include minerals such as limestone, frac sand, copper, lead and zinc. We lease a portion of these minerals to third parties in exchange for royalty payments. The structure of these leases is similar to our coal leases, and these leases typically require minimum rental payments in addition to royalties. During ~~2023~~ **2024** , we received $ 2. 9 million in aggregates royalty revenues, including overriding royalty revenues. Carbon Neutral Initiatives We continue to explore and identify ~~alternative~~ carbon neutral revenue sources across our large portfolio of surface, mineral, and timber assets, including the ~~permanent~~ sequestration of carbon dioxide (" CO2") **in our** underground **pore space** and ~~in~~ standing forests **, lithium production** , and the generation of electricity using geothermal, solar and wind energy ~~, as well as lithium production~~ . As with our existing mineral activities, we do not plan to develop or operate carbon sequestration or carbon neutral energy projects ourselves but we plan to lease our acreage to companies that will conduct those operations in exchange for payment of royalties and other fees to us. While the timing and likelihood of additional cash flows being realized from these activities is uncertain, we believe our large ownership footprint throughout the United States provides additional opportunities to create value in this regard and position us as a key beneficiary of the transitional energy economy with minimal capital investment. We executed our first carbon neutral project in ~~the fourth quarter of~~ 2021 through the sale of 1. 1 million carbon offset credits for $ 13. 8 million. The offset credits were issued to us by the California Air Resources Board under its cap- and- trade program and represent 1. 1 million metric tons of carbon sequestered in approximately 39, 000 acres of our forestland in West Virginia. We have the ability to harvest and sell future timber growth and in 2023, we sold carbon ~~offest~~ - **offset** credits related to 2022 growth for $ 0. 6 million **. Additionally, during 2024 we received approximately $ 13. 4 million from a third party related to its creation of California Air Resources Board carbon offset credits from our properties** . Carbon Sequestration. We own approximately 3. 5 million acres of specifically reserved subsurface rights in the southern United States with the potential for permanent sequestration of greenhouse gases. The carbon capture utilization and storage industry (" CCUS ") is in its infancy and the future is highly uncertain, but a few facts are clear. A sequestration project requires acreage possessing unique geologic characteristics, close proximity to sources of industrial- scale greenhouse gas emissions or direct air capture capability, and the appropriate form of legal title that grants the acreage owner the right to sequester emissions in the subsurface. **The demand for CCUS may be impacted by changes in the regulatory climate, including changes in environmental regulations. Changes in presidential administrations, or at a congressional level may result in periodic increases or decreases in CCUS projects.** While carbon sequestration rights and ownership continue to evolve, we believe we own one of the largest inventory of acreage with potential for carbon sequestration activities in the United States. In the first quarter of 2022 we executed our first subsurface CO2 sequestration lease on 75, 000 acres of underground pore space we own in southwest Alabama with the potential to store over 300 million metric tons of CO2 **; however, we were notified that this agreement would not be renewed for another lease term and has been terminated as per the lessee' s rights in the agreement** . In October of 2022, we announced our second subsurface CO2 transaction with the execution of a lease for approximately 65, 000 acres of pore space we control near southeast Texas with estimated storage capacity of at least 500 million metric tons of CO2 ~~. In total, we have approximately 140, 000 acres of pore space under lease for carbon sequestration with estimated CO2 storage capacity of 800 million metric tons~~ . Renewable Energy. In addition, we believe portions of our asset base across the United States possess the geologic characteristics and geographical locations necessary for geothermal, solar and wind energy development. With regards to geothermal, the technology to generate safe and reliable " green " electricity using heat found deep underground is advancing rapidly. Once limited to the geologic " hot spots, " new technology has made geothermal energy projects feasible in many places previously thought impossible. Our geothermal opportunities are predominately located in the South, Midwest and Northwest parts of the United States. In the third quarter of 2022 we executed our first geothermal lease with the potential to generate up to 15 megawatts of electricity. With regards to wind and solar energy opportunities, we are actively engaged in discussions for potential use of our acreage for these types of renewable energy developments predominantly in Kentucky and West Virginia. ~~In the first quarter of 2023 we executed a new solar lease.~~ Soda Ash Segment We own a 49 % non- controlling equity interest in Sisecam Wyoming. ~~Prior to 2023, Sisecam Resources LP owned 51 % interest in Sisecam Wyoming. Sisecam Resources LP was a publicly traded master limited partnership that depended on distributions from Sisecam Wyoming in order to make distributions to its public unitholders. In 2023, Sisecam Resources LP was dissolved and~~ Sisecam Chemicals Wyoming LLC (" SCW LLC") ~~became~~ **is** the direct owner of 51 % of Sisecam Wyoming. SCW LLC, our operating partner, controls and operates Sisecam Wyoming. SCW LLC is 100 % owned by Sisecam Chemicals Resources LLC (" Sisecam Chemicals,") which is ~~60~~ **100** % owned by Sisecam USA Inc. (" Sisecam USA ~~") and 40 % owned by Ciner Enterprises Inc. (" Ciner Enterprises~~ "). Sisecam USA is a direct wholly- owned subsidiary of Türkiye Şişe ve Cam Fabrikalari A. Ş, a Turkish Corporation (" Şişecam Parent"), which is an approximately 51 %- owned subsidiary of Turkiye Is Bankasi Turkiye Is Bankasi (" Isbank"). Şişecam Parent is a global company operating in soda ash, chromium chemicals, flat glass, auto glass, glassware glass packaging and glass fiber sectors. Şişecam Parent was founded over 88 years ago, is based in Turkey and is one of the largest industrial publicly- listed companies on the Istanbul exchange. With production facilities in several continents and in several countries, Sisecam is one of the largest glass and chemicals producers in the world. ~~Ciner Enterprises is a direct wholly- owned subsidiary of WE Soda Ltd., a U. K. Corporation (" WE Soda "). WE Soda is a direct wholly- owned subsidiary of KEW Soda Ltd., a U. K. corporation (" KEW Soda "), which is a direct wholly owned subsidiary of Akkan Enerji ve Madencilik Anonim Şirketi (" Akkan "). Akkan is directly and wholly owned by Turgay Ciner, the Chairman of the Ciner Group (" Ciner Group "), a Turkish conglomerate of companies engaged in energy and mining (including soda ash mining), media and shipping markets.~~ Sisecam Wyoming mines trona and processes it into soda ash that is sold both domestically and internationally into the glass and chemicals industries. As a minority interest owner in Sisecam Wyoming, we do not operate and are not involved in the day- to- day operation of the trona ore mine or soda ash production plant. We appoint three of the seven members of the Board of Managers of Sisecam Wyoming and have certain limited negative controls relating to the company. We have limited approval rights with respect to Sisecam Wyoming, and our partner controls most business decisions, including decisions with respect to distributions and capital expenditures. Sisecam Wyoming is one of the largest and lowest cost producers of soda ash in the world, serving a global market from its facility located in the Green River Basin of Wyoming. The Green River Basin geological formation holds the largest, and one of the highest purity, known deposits of trona ore in the world. Trona, a naturally occurring soft mineral, is also known as sodium sesquicarbonate and consists primarily of sodium carbonate, or soda ash, sodium bicarbonate and water. Sisecam Wyoming processes trona ore into soda ash, which is an essential raw material in flat glass, container glass, detergents, chemicals, paper and other consumer and industrial products. The vast majority of the world' s accessible trona is located in the Green River Basin. According to historical production statistics, approximately 30 % of global soda ash is produced by processing trona, with the remainder being produced synthetically through chemical processes. The costs associated with procuring the materials needed for synthetic production are greater than the costs associated with mining trona for trona- based production. In addition, trona- based production consumes less energy and produces fewer undesirable by-products than synthetic production. Sisecam Wyoming' s Green River Basin surface operations consist of leased and licensed subsurface mining areas in Wyoming. The facility is accessible by both road and rail. Sisecam Wyoming uses large continuous mining machines and underground shuttle cars in its mining operations. Its processing assets consist primarily of material sizing units, conveyors, calciners, dissolver circuits, thickener tanks, drum filters, evaporators and rotary dryers. **The following map provides an aerial overview of the Green River Basin surface operations: The following map shows the known sodium leasing area within the Green River Basin, including the boundaries of Sisecam Wyoming' s leased and licensed subsurface mining: The Green River Basin geological formation holds one of the largest and purest known deposits of trona ore in the world. Sisecam Wyoming' s reserves contain trona deposits having a purity between 80 % and 89 % by weight, which means that insoluble impurities and water make up approximately 11 % to 20 % of Sisecam Wyoming' s trona. Sisecam Wyoming' s mining leases and license are located in two mining beds, designated by the U. S. Geological Survey as beds 24 and 25, at depths of 850 to 800 feet near their shaft locations, respectively, below the surface. Mining these beds affords Sisecam Wyoming several competitive advantages. First, the depth of Sisecam Wyoming' s beds is shallower than other actively mined beds in the Green River Basin, which allows them to use a continuous mining technique to mine trona and roof bolt the ceiling simultaneously. In addition, mining two beds that are on top of one another allows for production efficiencies because Sisecam Wyoming is able to use a single hoisting shaft to service both beds. The following graphic shows a cross- section of the strategic areas of the Green River Basin where Sisecam Wyoming mines trona:** In trona ore processing, insoluble materials and other impurities are removed by thickening and filtering liquor, a solution consisting of sodium carbonate dissolved in water. Sisecam Wyoming then adds activated carbon to filters to remove organic impurities, which can cause color contamination in the final product. The resulting clear liquid is then crystallized in evaporators, producing sodium carbonate monohydrate. The crystals are then drawn off and passed through a centrifuge to remove excess water. The resulting material is dried in a product dryer to form anhydrous sodium carbonate, or soda ash. The resulting processed soda ash is then stored in on- site storage silos to await shipment by bulk rail or truck to distributors and end customers. The facility is in good working condition and has been in service for more than 60 years. ~~Deca Rehydration. The evaporation stage of trona ore processing produces a precipitate and natural by- product called deca." Deca," short for sodium carbonate decahydrate, is one part soda ash and ten parts water. Solar evaporation causes deca to crystallize and precipitate to the bottom of the four main surface ponds at the Green River Basin facility. The deca rehydration process enables Sisecam Wyoming to recover soda ash from the deca- rich purged liquor as a by- product of the refining process. The soda ash contained in deca is captured by allowing the deca crystals to evaporate in the sun and separating the dehydrated crystals from the soda ash. The separated deca crystals are then blended with partially processed trona ore in the dissolving stage of the production process. This process enables Sisecam Wyoming to reduce waste storage needs and convert what is typically a waste product into a usable raw material. Sisecam Wyoming anticipates that its current deca stockpiles will be exhausted by 2024 and that production rates will decline if that production capacity is not replaced.~~ Shipping and Logistics. For the year ended December 31, ~~2023~~ **2024** , Sisecam Wyoming assisted the majority of its domestic customers in arranging their freight services. All of the soda ash produced is shipped by rail or truck from the Green River Basin facility. For the year ended December 31, ~~2023~~ **2024** , Sisecam Wyoming shipped over 90 % of its soda ash to its customers initially via a single rail line owned and controlled by Union Pacific Railroad Company (" Union Pacific"). The Sisecam Wyoming plant receives rail service exclusively from Union Pacific. The agreement with Union Pacific expires on December 31, 2025 and there can be no assurance that it will be renewed on terms favorable to Sisecam Wyoming or at all. If Sisecam Wyoming does not ship at least a significant portion of its soda ash production on the Union Pacific rail line during a twelve- month period, they must pay Union Pacific a shortfall payment under the terms of its transportation agreement. During ~~2023~~ **2024** , Sisecam Wyoming had no shortfall payments and does not expect to make any such payments in the future. A leased fleet of hopper cars serve as dedicated modes of shipment to Sisecam Wyoming' s domestic and international customers. For exports, soda ash is shipped on unit trains primarily out of Longview, Washington for bulk shipments. Sisecam Wyoming has contracts securing its export capacity in bulk vessels and containers vessels. From these ports, soda ash is loaded onto ships for delivery to ports all over the world. Sisecam Wyoming ships to customers on Cost and Freight (" CFR") and Cost, Insurance, and Freight (" CIF") basis where they pay for ocean freight and charge the customer directly for these freight costs. Sisecam Wyoming has yearly and multiyear contracts for a portion of its ocean freight with vessel owners and carriers securing capacity and reducing market risk fluctuation. Customers. Sisecam Wyoming generated approximately half of its gross revenue from export sales, which consist of both customers as well as distributors who serve as its channel partners in certain markets. For customers in North America, Sisecam Chemicals ~~Resources~~ typically enters into contracts on Sisecam Wyoming' s behalf with terms ranging from one to three years. Under these contracts, customers generally agree to purchase either minimum estimated volumes of soda ash or a certain percentage of their soda ash requirements at a fixed price for a given calendar year. Although Sisecam Wyoming does not have " take or pay " arrangements with its customers, substantially all sales are made pursuant to written agreements and not through spot sales Sisecam Wyoming' s customers consist primarily of glass manufacturing companies, which account for 50 % or more of the consumption of soda ash around the world, and chemical and detergent manufacturing companies. Sisecam Chemicals has now completed ~~three~~ **four** full years directly managing its international sales, marketing and logistics activities since exiting **American Natural Soda Ash Corporation ("** ANSAC **")** at the end of 2020. Sisecam Chemicals took direct control of these activities to improve access to customers and gain control over placement of its sales in the international marketplace. This enhanced view of the global market allows Sisecam Chemicals to better understand supply / demand fundamentals thus allowing better decision making for its business. Sisecam Chemicals continues to optimize its distribution network leveraging strengths of existing distribution partners while expanding as its business requires in certain target areas. Leases and License. Sisecam

Wyoming is party to several mining leases and one license for its subsurface mining rights. Some of the leases are renewable at Sisecam Wyoming’ s option upon expiration. Sisecam Wyoming pays royalties to the ~~State~~ **state** of Wyoming, the U. S. Bureau of Land Management ~~and~~ **,** Sweetwater Royalties LLC, a subsidiary of Sweetwater Trona OpCo LLC and the successor in interest to the license with the Rock Springs Royalty Company LLC, an affiliate of Occidental Petroleum Corporation (formerly an affiliate of Anadarko Petroleum Corporation) **, and other private paarties which provide for royalties based upon production volume** . The royalties are calculated based upon a percentage of the value of soda ash and related products sold at a certain stage in the mining process. These royalty payments may be subject to a minimum domestic production volume from the Green River Basin facility. Sisecam Wyoming is also obligated to pay annual rentals to its lessors and licensor regardless of actual sales. In addition, Sisecam Wyoming pays a production tax to Sweetwater County, and trona severance tax to the State of Wyoming that is calculated based on a formula that utilizes the volume of trona ore mined and the value of the soda ash produced. Sisecam Wyoming has a perpetual right to continue operating under these leases and license as long as it maintains continuous mining operations and intends to continue renewing the leases and license as has been historical practice. As a minority interest owner in Sisecam Wyoming, we do not operate and are not involved in the day- to- day operation of the trona ore mine or soda ash production plant. Our partner, SCW **LLC** , manages the mining and plant operations. We appoint three of the seven members of the Board of Managers of Sisecam Wyoming and have certain limited negative controls relating to the company. **Sisecam Wyoming produced 2. 5 million, 2. 6 million and 2. 8 million short tons of soda ash (of which the Partnership' s interest is 1. 2 million, 1. 3 million and 1. 4 million short tons of soda ash) during the year ended December 31, 2024, 2023 and 2022, respectively. Sisecam Wyoming sold 2. 5 million, 2. 7 million and 2. 7 million short tons of soda ash (of which the Partnership' s interest is 1. 2 million, 1. 3 million and 1. 3 million short tons of soda ash) during the year ended December 31, 2024, 2023 and 2022, respectively. Sisecam Wyoming had net sales of $ 578. 1 million, $ 773. 6 million and $ 720. 1 million (of which the Partnership' s interest is $ 283. 3 million, $ 379. 1 million and $ 352. 8 million) during the year ended December 31, 2024, 2023 and 2022, respectively. Cautionary Note to Investors Regarding Estimates Of Measured, Indicated And Inferred Resources And Proven And Probable Mineral Reserves We are subject to the reporting requirements of the Exchange Act governed by S- K 1300 that aim to convey an appropriate level of confidence in the disclosures being reported. In our public filings we disclose proven and probable reserves and measured, indicated and inferred resources, each as defined in S- K 1300. The estimation of measured resources and indicated resources involve greater uncertainty as to their existence and economic feasibility than the estimation of proven and probable reserves, and therefore investors are cautioned not to assume that all or any part of measured or indicated resources will ever be converted into S- K 1300- compliant reserves. The estimation of inferred resources involves far greater uncertainty as to their existence and economic viability than the estimation of other categories of resources, and therefore it cannot be assumed that all or any part of inferred resources will ever be upgraded to a higher category. Therefore, investors are cautioned not to assume that all or any part of inferred resources exist, or that they can be mined legally or economically. Trona Resources and Trona Reserves Information concerning Sisecam Wyoming' s mining property and estimated mineral resources and mineral reserves in this Form 10- K has been prepared in accordance with the requirements of S- K 1300 which requires us to disclose Sisecam Wyoming' s mineral resources, in addition to Sisecam Wyoming' s mineral reserves, at Sisecam Wyoming' s mining property as of the end of our most recently completed fiscal year. The information that follows is derived, for the most part, from, and in some instances is an extract from the technical report summary prepared by Hollberg Professional Group (“ HPG ”) in compliance with Item 601 (b) (96) and S- K 1300 completed on February 27, 2025 (the “ 2024 TRS ”). Portions of the following information are based on assumptions, qualifications and procedures, that are not fully described herein. Reference should be made to the full text of the technical report summary prepared by HPG attached as Exhibit 96. 1 and incorporated herein by reference and made a part of this Form 10- K. We have used the term “ trona ” as in “ trona resources ” and “ trona reserves ” interchangeably with “ mineral. ” HPG has conducted an independent technical review of the lands held by Sisecam Chemicals referred to as the “ Big Island Mine, ” which is located in the area commonly referred to as the Known Sodium Lease Area (the “ KSLA ”) near the town of Green River, Sweetwater County. The KSLA is where trona thickness exceeds 1- meter, extends for over 300 km2, and is greater than 80 % grade. The U. S. Geological Survey recognizes 25 trona beds of economic importance (at least 1 meter in thickness and 300 km2 in areal extent) within the Green River Basin. Identified in ascending order, the trona beds are numbered 1 through 25 from the oldest (stratigraphically lowest) to the youngest (stratigraphically highest). Sisecam Wyoming has approximately 23, 999 acres of trona under lease made up of approximately 8, 094 Federal acres, 2, 986 State acres, and 12, 919 private acres. Sisecam Chemicals has mineral resources and mineable reserves in the shallowest mechanically mineable Trona beds 24 and 25, at depths of 850 and 800 feet below the surface, respectively, at our mine shaft locations. See also certain maps and graphics of Sisecam Wyoming' s property above. HPG estimated the total of the Big Island Mine’ s remaining leased and licensed proven and probable trona reserves as 217. 7 million short tons (of which the Partnership’ s interest is 106. 7 million short tons) as of December 31, 2024, compared to 211. 3 million short tons (of which the Partnership’ s interest was 103. 5 million short tons) as of December 31, 2023 and the total of the measured and indicated in- place trona resources exclusive of reserves as 153. 3 million short tons (of which the Partnership’ s interest is 75. 1 million short tons) as of December 31, 2024, compared to 162. 3 million short tons (of which the Partnership' s interest was 79. 5 million short tons) as of December 31, 2023. As of December 31, 2024, the increase of 6. 4 million short tons of the Big Island Mine’ s proven and probable trona reserves, or 3. 0 %, as compared to December 31, 2023 is due to to the net result of reductions from mining activities, additions due to lease acquisition and additions due to geologic model modifications. The cutoff grade of greater than 75 % trona and thickness greater than 6 feet is applied to estimate the trona resources based upon successful mining and processing of the lower grade trona beds 19, 20** and 21 which were considered viable mining prospects by Texas Gulf Soda Ash (“ TGSA ”). The mineral resource inclusive of the mineral reserves is that portion of the ore body that is considered either economically viable for mining and can be converted to reserves or of economic interest but considered outside the current economic limits. This is the material considered of economic interest that has the potential to be converted to reserves. Sisecam Wyoming' s trona resources are categorized as “ Measured mineral resources, ” “ Indicated mineral resources, ” and “ Inferred mineral resources, ” which are defined as follows: • Measured mineral resources- Mineral resources for which quantity and grade or quality are estimated on the basis of conclusive geological evidence and sampling. The level of geological certainty associated with a measured mineral resource is sufficient to allow a qualified person to apply modifying factors, as defined in this section, in sufficient detail to support detailed mine planning and final evaluation of the economic viability of the deposit. Because a measured mineral resource has a higher level of confidence than the level of confidence of either an indicated mineral resource or an inferred mineral resource, a measured mineral resource may be converted to a proven mineral reserve or to a probable mineral reserve. • Indicated mineral resources- Mineral resources for which quantity and grade or quality are estimated on the basis of adequate geological evidence and sampling. The level of geological certainty associated with an indicated mineral resource is sufficient to allow a qualified person to apply the modifying factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Because an indicated mineral resource has a lower level of confidence than the level of confidence of a measured mineral resource, an indicated mineral resource may only be converted to a probable mineral reserve. (The modifying factors are the factors that a qualified person must apply to indicated and measured mineral resources and then evaluate in order to establish the economic viability of mineral reserves. A qualified person must apply and evaluate modifying factors to convert measured and indicated mineral resources to proven and probable mineral reserves. These factors include but are not restricted to mining; processing; metallurgical; infrastructure; economic; marketing; legal; environmental compliance; plans, negotiations, or agreements with local individuals or groups; and governmental factors. The number, type and specific characteristics of the modifying factors applied will necessarily be a function of and depend upon the mineral, mine, property, or project.) • Inferred mineral resources- Mineral resources for which quantity and grade or quality are estimated on the basis of limited geological evidence and sampling. The level of geological uncertainty associated with an inferred mineral resource is too high to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner useful for evaluation of economic viability. Because an inferred mineral resource has the lowest level of geological confidence of all mineral resources, which prevents the application of the modifying factors in a manner useful for evaluation of economic viability, an inferred mineral resource may not be considered when assessing the economic viability of a mining project and may not be converted to a mineral reserve. The following is a summary of the recoverable trona reserves for beds 24 and 25 as of December 31, 2024: (in millions of short tons except percentage) (1) (2) Reserve Category Proven mineral reserves Probable mineral reserves Total mineral reserves Amount Grade (1) Amount Grade (1) Amount Grade (1) Lower Bed 24 69. 7 85. 9 % 75. 2 85. 6 % 145. 0 85. 8 % Upper Bed 25 39. 5 85. 6 % 33. 3 84. 8 % 72. 8 85. 3 % Total (3) (4) (5) 109. 2 85. 8 % 108. 5 85. 3 % 217. 7 85. 6 % (1) Numbers have been rounded; totals may not sum due to rounding. (2) Based on a 7- foot minimum thickness and an 85 % minimum grade cut- off. (3) The point of reference is run- of- mine (ROM) ore delivered to the processing facilities including mining losses and dilution. (4) Mineral reserves are current as of December 31, 2024, using the definitions in S- K 1300. (5) Mineral reserves are reported on a 100 % ownership basis. Sisecam Wyoming is owned 51 % by SCW LLC and 49 % by NRP. Sisecam Wyoming' s reserves are subject to leases with the State of Wyoming and the U. S. Bureau of Land Management and a license with Sweetwater Royalties LLC. The following table presents Sisecam Wyoming' s estimated proven and probable trona reserves by license and leases as of December 31, 2024: (in millions of short tons except percentage) (1) (2) Reserve Category Proven mineral reserves Probable mineral reserves Total mineral reserves Amount Grade (1) Amount Grade (1) Amount Grade (1) License with Sweetwater Royalties LLC 55. 7 85. 9 % 55. 1 85. 3 % 110. 8 85. 6 % Leases with the U. S. Government 45. 6 85. 6 % 34. 6 85. 3 % 80. 2 85. 4 % Leases with the State of Wyoming 8. 0 86. 7 % 18. 8 85. 9 % 26. 8 86. 1 % Total (3) (4) (5) 109. 2 85. 8 % 108. 5 85. 3 % 217. 7 85. 6 % (1) Numbers have been rounded; totals may not sum due to rounding. (2) Based on a 7- foot minimum thickness and an 85 % minimum grade cut- off. (3) The point of reference is ROM ore delivered to the processing facilities including mining losses and dilution. (4) Mineral reserves are current as of December 31, 2024, using the definitions in S- K 1300. (5) Mineral reserves are reported on a 100 % ownership basis. Sisecam Wyoming is owned 51 % by SCW LLC and 49 % by NRP. The following is a summary of the measured, indicated, and inferred mineral resources exclusive of reserves for trona beds 24 and 25 as of December 31, 2024: (in millions of short tons except percentage and thickness) (1) (2) Reserve Category Measured mineral resources Indicated mineral resources Measured Indicated mineral resources Inferred mineral resources Amount Grade (1) Amount Grade (1) Amount Grade (1) Thickness (ft) Amount Grade (1) Lower Bed 24 45. 4 88. 5 % 53. 6 86. 6 % 99. 1 87. 5 % 8. 6 — — % Upper Bed 25 29. 3 84. 9 % 25. 0 86. 2 % 54. 3 85. 5 % 7. 9 — — % Total (3) (4) (5) 74. 7 87. 1 % 78. 7 86. 5 % 153. 3 86. 8 % 8. 3 — — % (1) Numbers have been rounded; totals may not sum due to rounding. (2) Based on a 6- foot minimum thickness and a 75 % minimum grade cut- off. (3) The point of reference is in- place inclusive of impurities and insoluble content. (4) Mineral reserves are current as of December 31, 2024, using the definitions in S- K 1300. (5) Mineral reserves are reported on a 100 % ownership basis. Sisecam Wyoming is owned 51 % by SCW LLC and 49 % by NRP. HPG estimated proven and probable reserves of approximately 217. 7 million short tons of trona (of which the Partnership’ s interest is 106. 7 million short tons), which is equivalent to 118. 0 million short tons of soda ash as of December 31, 2024 (of which the Partnership’ s interest is 57. 8 million short tons of soda ash). Based on Sisecam Wyoming' s current mining rate of approximately 4. 3 million short tons of trona per year, Sisecam Wyoming has enough proven and probable trona reserves to continue mining trona using current methods for approximately 50 years. The mineral reserve is the economically mineable part of a measured or indicated mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted. Sisecam Wyoming' s trona reserves are categorized as " Proven mineral reserves " and " Probable mineral reserves, " which are defined as follows: • Proven mineral reserves- The economically mineable part of a measured mineral resource and can only result from conversion of a measured mineral resource. • Probable mineral reserves- The economically mineable part of an indicated and, in some cases, a measured mineral resource. In determining the reserve parameters and assumptions HPG considered the following circumstances: • Sisecam Wyoming' s 60- year long history and economics of mining the deposit and producing soda ash; ◦ The 183. 3 million short tons (" Mst ") of trona ore produced from these two beds; • The projected long life of the mine and resulting likely change in economics, mining, and processing methods over its projected 40 plus- year mine life (considering increased production over the current production rates) used in this technical summary. This 40 plus- year mine life consideration is based on the specific assumptions in this technical summary, including assumptions related to projected timing and estimated cost of two- seam mining, timing of related capital expenditures and sales price projections; • Sisecam Wyoming' s current processing facilities' capabilities and projected future changes to these facilities; • The economics associated with Sisecam Wyoming' s current mining equipment and history of " high grading " the thickest portions of the deposit; • Sisecam Wyoming' s current mining equipment limitations and required future changes to these systems; and • HPG' s knowledge of operating and managing other trona and potash mines. In determining whether the reserves meet these economic standards, HPG made certain assumptions regarding the remaining life of the Big Island Mine, including, among other things, that: • the cost of products sold per short ton will remain consistent with Sisecam Wyoming' s cost of products sold for the five years ended December 31, 2024; • the weighted average net sales per short ton FOB plant, $ 165 / ton, based on USGS pricing and historical pricing provided by Sisecam Wyoming; • Sisecam Wyoming' s mining costs will remain consistent with the five years ended December 31, 2024, until they begin two- seam mining, at which time mining costs for the two- seam mining tonnage could increase by as much as 30 %; • Sisecam Wyoming' s processing costs will remain consistent with the five years ended December 31, 2024, and rise in 10- years to account for lower grade material; • Sisecam Wyoming will achieve an annual mining rate of approximately 4. 3 million short tons of trona in 2025 and beyond; • Sisecam Wyoming will process soda ash with a 90 % rate of recovery, without accounting for the deca rehydration process; • the ore to ash ratio for the stated trona reserves is 1. 835: 1. 0 (short tons of trona run- of- mine to short tons of soda ash); • The run- of- mine ore estimate contains dilution from the mining process; • Sisecam Wyoming will continue to conduct only conventional mining using the room and pillar method and a non- subsidence mine design; • Sisecam Wyoming will, in approximately 10 years, make necessary modifications to the processing facilities to allow localized mining of 75 % ore grade in areas where the floor seam or insoluble disruptions have moved up into the mining horizon causing mining to be halted early due to processing facility limitations; • Sisecam Wyoming will, in approximately 20 years, make necessary equipment modifications to operate at a seam height of 7- feet, the current mining limit is 9- feet; • Sisecam Wyoming has and will continue to have valid leases and license in place with respect to the reserves, and that these leases and license can be renewed for the life of the mine based on their extensive history of renewing leases and license; • Sisecam Wyoming has and will continue to have the necessary permits to conduct mining operations with respect to the reserves; and • Sisecam Wyoming will maintain the necessary tailings storage capacity to maintain tailings disposal between the mine and surface placement for the life- of- mine. Sisecam Wyoming' s estimates of mineral resources and mineral reserves will change from time to time as a result of mining activities, analysis of new engineering and geologic data, modification of mining plans or mining methods and other factors. For additional information, see" Item 1A. Risk Factors, Risks Related to Our Business " for more information regarding risks surrounding Sisecam Wyoming' s reserves. Internal Controls Disclosure over Trona Resources and Trona Reserves Sisecam Wyoming has internal controls over the trona resources and trona reserves estimation processes that result in reasonable and reliable estimates aligned with industry practice and reporting regulations. Annually, qualified persons and other Sisecam Wyoming employees review the estimates of trona resources and trona reserves and the supporting documentation, and based on their review of such information recommend approval to use the trona resources and trona reserves estimates to Sisecam Wyoming senior management. Sisecam Wyoming' s controls utilize management systems, including, but not limited to, standardized procedures, workflow processes, supervision and management approval, internal and external reviews and audits, reconciliations, and data security covering record keeping, chain of custody and data storage. Sisecam Wyoming' s systems also cover sample preparation and analysis, data verification, trona processing, metallurgical testing, recovery estimation, mine design and sequencing, and trona resource and reserve evaluations, with environmental, social and regulatory considerations. These controls and other methods help to validate the reasonableness of the estimates. The effectiveness of the controls is reviewed periodically to address changes in conditions and the degree of compliance with policies and procedures. For additional information regarding the risks associated with Sisecam Wyoming' s estimates of trona resources and reserves, see" Item 1A. Risk Factors, Risks Related to Our Business — Sisecam Wyoming' s reserve and resource data are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future, which could materially and adversely affect the quantities and value of Sisecam Wyoming' s reserves and resources. " The technical data underlying the mineral resources and reserves estimates included in this Annual Report on Form 10- K, including the internal controls for determining and reporting such mineral resources and reserves estimates, are maintained by Sisecam Wyoming, and our agreements with Sisecam Wyoming do not give us (i) access to such underlying technical data sufficient to specifically confirm the opinion of the qualified person with respect to such resources and reserves or (ii) the ability to monitor or enforce Sisecam Wyoming' s

internal controls for determining and reporting such resources and reserves. Sisecam Wyoming has, however, made representations to us and the qualified person that it does not have reason to believe that the underlying technical data is materially misleading, and that Sisecam Wyoming' s internal controls were applied to the mineral resource and reserve information contained in the report. We are providing this information because it represents the information that we have in our possession and we do not have a reasonable ground to believe that it is inaccurate, but we caution investors that we have relied on the qualified person and Sisecam Wyoming with respect to the preparation of the mineral resources and reserves estimates included in this report and are not able to independently verify its accuracy. Investors are cautioned to consider such risks when reviewing the mineral resources and reserves estimates included in this report. Significant Customers We have a significant concentration of revenues from Alpha, with total revenues of $ ~~86~~ **67** . ~~1~~ **7** million in ~~2023~~ **2024** from several different mining operations, including wheelage revenues and coal overriding royalty revenues. We also have a significant concentration of revenues with Foresight and its subsidiaries, with total revenues of $ ~~60~~ **39** . ~~5~~ **2** million in ~~2023~~ **2024** from all of their mining operations, including transportation and processing services revenues, coal overriding royalty revenues and wheelage **revenues. We also have a significant concentration of revenues with Alabama Kanu with total revenues of $ 29. 5 million in 2024 from one mining operation, including overriding royalty** revenues. For additional information on significant customers, refer to" Item 8. Financial Statements and Supplementary Data — Note 14. Major Customers." Competition We face competition from land companies, coal producers, international steel companies and private equity firms in purchasing coal and royalty producing properties. Numerous producers in the coal industry make coal marketing intensely competitive. Our lessees compete among themselves and with coal producers in various regions of the United States for domestic sales. Lessees compete with both large and small producers nationwide on the basis of coal price at the mine, coal quality, transportation cost from the mine to the customer and the reliability of supply. Continued demand for our coal and the prices that our lessees obtain are also affected by demand for electricity and steel, as well as government regulations, technological developments and the availability and the cost of generating power from alternative fuel sources, including nuclear, natural gas, wind, solar and hydroelectric power. Sisecam Wyoming' s trona mining and soda ash refinery business faces competition from a number of soda ash producers in the United States, Europe and Asia, some of which have greater market share and greater financial, production and other resources than Sisecam Wyoming does. Some of Sisecam Wyoming' s competitors are diversified global corporations that have many lines of business and some have greater capital resources and may be in a better position to withstand a long- term deterioration in the soda ash market. Other competitors, even if smaller in size, may have greater experience and stronger relationships in their local markets. Competitive pressures could make it more difficult for Sisecam Wyoming to retain its existing customers and attract new customers, and could also intensify the negative impact of factors that decrease demand for soda ash in the markets it serves, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of soda ash. Title to Property We owned substantially all of our coal and aggregates mineral rights in fee as of December 31, ~~2023~~ **2024** . We lease the remainder from unaffiliated third parties. Sisecam Wyoming leases or licenses its trona. We believe that we have satisfactory title to all of our mineral properties, but we have not had a qualified title company confirm this belief. Although title to these properties is subject to encumbrances in certain cases, such as customary easements, rights- of- way, interests generally retained in connection with the acquisition of real property, licenses, prior reservations, leases, liens, restrictions and other encumbrances, we believe that none of these burdens will materially detract from the value of our properties or from our interest in them or will materially interfere with their use in the operation of our business. For most of our properties, the surface, oil and gas and mineral or coal estates are not owned by the same entities. Some of those entities are our affiliates. State law and regulations in most of the states where we do business require the oil and gas owner to coordinate the location of wells so as to minimize the impact on the intervening coal seams. We do not anticipate that the existence of the severed estates will materially impede development of the minerals on our properties. Regulation and Environmental Matters Operations on our properties must be conducted in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws and management of electrical equipment containing polychlorinated biphenyls (" PCBs"). Because of extensive, comprehensive and often ambiguous regulatory requirements, violations during natural resource extraction operations are not unusual and, notwithstanding compliance efforts, we do not believe violations can be eliminated entirely. While it is not possible to quantify the costs of compliance with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. Our lessees in our coal and aggregates royalty businesses are required to post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closures, including the cost of treating mine water discharge when necessary. In many states our lessees also pay taxes into reclamation funds that states use to achieve reclamation where site specific performance bonds are inadequate to do so. Determinations by federal or state agencies that site specific bonds or state reclamation funds are inadequate could result in increased bonding costs for our lessees or even a cessation of operations if adequate levels of bonding cannot be maintained. We do not accrue for reclamation costs because our lessees are both contractually liable and liable under the permits they hold for all costs relating to their mining operations, including the costs of reclamation and mine closures. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. In recent years, compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers. In addition, the electric utility industry, which is the most significant end- user of thermal coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which has affected and is expected to continue to affect demand for coal mined from our properties. Current and future proposed legislation and regulations could be adopted that will have a significant additional impact on the mining operations of our lessees or their customers' ability to use coal and may require our lessees or their customers to change operations significantly or incur additional substantial costs that would negatively impact the coal industry. Many of the statutes discussed below also apply to Sisecam Wyoming' s trona mining and soda ash production operations, and therefore we do not present a separate discussion of statutes related to those activities, except where appropriate. Air Emissions The Clean Air Act and corresponding state and local laws and regulations affect all aspects of our business. The Clean Air Act directly impacts our lessees' coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non- hazardous air pollutants. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal- fired electric power generating plants. There have been a series of federal rulemakings that are focused on emissions from coal- fired electric generating facilities, including the Cross- State Air Pollution Rule (" CSAPR"), regulating emissions of nitrogen oxide (" NOx") and sulfur dioxide, and the Mercury and Air Toxics Rule (" MATS"), regulating emissions of hazardous air pollutants. In March 2021, the U. S. Environmental Protection Agency (" EPA") revised the CSAPR to require additional emissions reductions of NOx from power plants in twelve states. Further, in April 2022, EPA published a proposed rule to build on the CSAPR by imposing Federal Implementation Plans on over 20 states to implement the National Ambient Air Quality Standards (" NAAQS") for ozone. However, on August 21, 2023, the EPA announced a new review of the ozone NAAQS in combination with its reconsideration of EPA' s December 2020 decision to retain the 2015 NAAQS. The EPA **' s review remains ongoing and it** is ~~expected to release~~ **uncertain when the EPA will complete** its ~~Integrated Review~~ **review** ~~Plan~~ **. More recently,** in **December** ~~the fall of~~ 2024 **, the EPA issued a rule to revise the secondary NAAQS for sulfur oxides, but retained without revision the secondary standards for oxides of nitrogen and particulate matter. In May 2024, the EPA published a final rule to amend the MATS rule, which further limits the emission of non- mercury hazardous air pollutant metals from existing coal- fired power plants, tightens the emission standard for mercury for existing lignite- fired power plants, and strengthens emissions monitoring and compliance requirements. This final rule was challenged by various states and industry groups in the U. S. Court of Appeals for the D. C. Circuit. Although the lawsuit remains ongoing, the Supreme Court denied the challengers' request for a stay, so the implementation of the rule will continue as promulgated. Although the impacts of the May 2024 final rule are unknown, the MATS rule program has already forced electric power generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal- fired generating units and many electric power generators have already announced retirements due to the uncertainty surrounding the MATS rule** . Installation of additional emissions control technologies and other measures required under EPA regulations make it more costly to operate coal- fired power plants and could make coal a less attractive or even effectively prohibited fuel source in the planning, building and operation of power plants in the future. These rules and regulations have resulted in a reduction in coal' s share of power generating capacity, which has negatively impacted our lessees' ability to sell coal and our coal- related revenues. Further reductions in coal' s share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal- related revenues. The EPA' s regulation of methane under the Clean Air Act may also affect oil and gas production on properties in which we hold oil and gas interests. In December 2023, the EPA issued its methane rules, known as OOOOb and OOOOc, that establish new source and first- time existing source standards of performance for GHG and VOC emissions for crude oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities. **The final rules are currently being challenged by 23 states and a coalition of industry groups in the U. S. Circuit Court of Appeals for the D. C. Circuit, although OOOOb is already in effect. However, the new administration might take action to repeal or modify the methane rules though we cannot predict whether such action will occur or its timing. To the extent the methane rules are implemented as originally promulgated, compliance with the new rules may affect the amount oil & gas companies owe under the Inflation Reduction Act, which amended the CAA to impose a first- time fee on the emission of methane from sources required to report their GHG emissions to the EPA. The methane emissions fee applies to excess methane emissions from certain facilities and starts at $ 900 per metric ton of leaked methane in 2024 and increases to $ 1, 200 in 2025 and $ 1, 500 in 2026 and thereafter. In November 2024, the EPA finalized a rule, applicable to oil and gas facilities that emit more than 25, 000 metric tons of CO2 per year, to implement the methane emissions fee provisions of the Inflation Reduction Act.** We **cannot** ~~are unable to~~ predict ~~at this time the impact of~~ **whether, how, or when** ~~these~~ -- **the** ~~requirements on any such~~ **new administration might take action to revise or repeal the methane fee rule. Additionally, Congress may take actions to repeal or revise the Inflation Reduction Act, including with respect to the methane emissions fee, which timing or outcome similarly cannot be predicted. To the extent that the methane emissions fee rule is implemented as originally promulgated,** oil and gas production on ~~our~~ **the** properties **in which we hold oil and gas interests could be adversely affected to the extent the rules and any of their requirements impose increased operating costs on the oil and gas industry** . Carbon Dioxide and Greenhouse Gas (" GHG") Emissions In December 2009, EPA determined that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and welfare because emissions of such gases are, according to EPA, contributing to warming of the Earth' s atmosphere and other climatic changes. Based on its findings, EPA began adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act. In August 2015, EPA published its final Clean Power Plan (" CPP") Rule, a multi- factor plan designed to cut carbon pollution from existing power plants, including coal- fired power plants. The rule required improving the heat rate of existing coal- fired power plants and substituting lower carbon- emission sources like natural gas and renewables in place of coal. As promulgated, the rule would **have** ~~force~~ **forced** many existing coal-fired power plants to incur substantial costs in order to comply or alternatively result in the closure of some of these plants, likely resulting in a material adverse effect on the demand for coal by electric power generators. **Following a legal** ~~The rule was being challenged~~ - **challenge** ~~by several states~~ , ~~industry participants and other~~ -- **the** ~~parties in the United States Court of Appeals for the District of Columbia Circuit. In February 2016, the Supreme Court of the United States stayed the CPP Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court. In April 2017, the United States Court of Appeals for the District of Columbia Circuit granted EPA' s motion to hold the litigation in abeyance. In December 2017, EPA issued a proposed rule repealing the CPP Rule and issued an Advance Notice of Proposed Rulemaking soliciting information regarding a potential replacement rule to the CPP Rule. In August 2018,~~ EPA formally proposed the Affordable Clean Energy (" ACE") Rule, which ~~would replace~~ **replaced** ~~the CPP Rule. The ACE Rule contemplates a narrower approach than the CPP Rule, focusing on efficiency improvements at existing power plants and eliminating the CPP Rule' s broader goals that envisioned switches to non- fossil fuel energy sources and the implementation of efficiency measures on demand- side entities, which the EPA now considers beyond the reach of its authority under the Clean Air Act. The ACE Rule would also omit specific numerical emissions targets that had been established under~~ the CPP Rule. The ACE Rule went into effect on September 6, 2019 **and** ~~. As a result, the United States Court of Appeals for the District of Columbia Circuit dismissed the pending challenges to the CPP Rule as moot. The ACE Rule~~ was **also subject to a** ~~challenged by public health groups, environmental groups, states, municipalities, industry groups, and power providers. The~~ legal ~~challenges~~ - **challenge** ~~were consolidated as American Lung Assoc. v. EPA before the D. C. Circuit Court of Appeals. Dozens of parties and over 170 amici filed briefs on the merits, and oral argument was held before a three- judge panel in October 2020~~ . In January 2021, the D. C. Circuit issued a written opinion holding that the ACE Rule was based on EPA' s " erroneous legal premise " that when it determines the " best system of emission reduction " for existing sources, the Clean Air Act mandates that EPA may only consider emission reduction measures that can be applied at and / or to a stationary source (often referred to as " inside- the- fence " measures). The Court vacated the rule, essentially reimplementing the CPP and leaving EPA to decide whether to stick with the CPP or to pursue a new rulemaking. In June 2022, the Supreme Court issued a written opinion, West Virginia v. EPA, in which the Court invalidated the CPP because EPA lacked the authority to promulgate such an expansive rule under the " Major Questions Doctrine. " ~~It is unclear~~ **Most recently, in May 2024, the EPA finalized a rule that repeals the ACE rule and establishes GHG standards and guidelines that require coal fired power plants to (1) convert to natural gas co-firing by January 1, 2030 and then retire by 2039, (2) install by 2032 carbon capture and sequestration technology capable of capturing 90 % of all CO2 emissions, or (3) cease operations by 2032. The May 2024 rule has been challenged in the U. S. Circuit Court of Appeals, but the U. S. Supreme Court denied the challengers' request to stay implementation of the rule pending the outcome of the litigation. The EPA recently filed a motion to hold the case in abeyance while the EPA reviews the May 2024 rule. However, we cannot predict what action the new administration may take with respect to the May 2024 rule. Notwithstanding the previous litigation, the CPP and the ACE led to premature retirements, and the new rule could lead to additional premature retirements of coal- fired generating units and reduce the demand for coal. Congress has not yet adopted legislation to restrict carbon dioxide emissions from existing power plants and has not otherwise expanded the legal authority of the EPA following West Virginia v. EPA, but we cannot predict** whether **such legislation** ~~the Biden administration~~ will **be passed in** ~~issue a replacement of~~ the ~~CPP~~ **future or what the potential impacts of such legislation would be** . In October 2015, EPA published its final rule on performance standards for greenhouse gas emissions from new, modified, and reconstructed electric generating units. The final rule requires new steam generating units to use highly efficient supercritical pulverized coal boilers that use partial post-combustion carbon capture and storage technology. **Following a legal challenge, the** ~~The final emission standard is less stringent than~~ EPA **undertook** ~~had originally proposed due to updated cost assumptions, but could still have~~ a **review of the October 2015** ~~material adverse effect on new coal- fired power plants. The final~~ rule ~~has been challenged by several states~~ , ~~industry participants~~ and ~~other parties in the United States Court of Appeals for the District of Columbia Circuit~~ , ~~but is not subject to a stay. In April 2017, the court granted EPA' s motion to hold the litigation~~ in ~~abeyance while EPA reviews the rule. In~~ December 2018, EPA issued a proposed rule revising the best system of emission reduction (" BSER ") for newly constructed coal- fired electric generating units, among other changes, to replace the 2015 rule. In a status report filed with the Court on January 15, 2021, EPA requested that the case remain in abeyance until after the transition to the Biden administration. On March 17, 2021, in line with President Biden' s Executive Order 13990, EPA asked the D. C. Circuit to vacate and remand the " significant contribution " final rule. On April 5, 2021, the D. C. Circuit vacated and remanded the January 2021 final rule. **In** ~~Although the EPA has not taken further action on the December 2018 proposed rule, on~~ May ~~23, 2023~~ **2024** , the EPA issued a ~~proposed~~ **final NSPS** rule ~~setting proposed new source performance standards~~ for **GHG** ~~greenhouse gas~~ emissions from new ~~, modified,~~ and reconstructed fossil fuel- fired ~~electric generating units; emission guidelines~~ **combustion turbines, which notably, formally withdrew the December 2018 proposed amendments to the NSPS** for **GHG** ~~greenhouse gas~~ emissions from **coal** ~~existing fossil fuel~~ - fired **EGUs, However,** ~~electric generating units; and repeal of~~ the ~~ACE Rule. The final~~ **EPA noted it was still continuing to review the October 2015** rule ~~is expected in 2024~~ . Certain authorizations required for certain mining and oil and gas operations may be difficult to obtain or use due to challenges from environmental advocacy groups to the environmental analyses conducted by federal agencies before granting permits. In particular, those approvals necessary for certain coal activities that are subject to the requirements of the National Environmental Policy Act (" NEPA ") are subject to real uncertainty. In April 2022, the Council on Environmental Quality (" CEQ ") issued a final rule, which is considered " Phase I " of the Biden Administration' s two- phased approach to modifying the NEPA, revoking some of the modifications made to the NEPA regulations under the previous administration and reincorporating the consideration of direct, indirect, and cumulative effects of major federal actions, including GHG emissions. In ~~July~~ **May** ~~2023~~ **2024** , the CEQ ~~announced a~~ **finalized the** " Phase 2 " **updates** ~~Notice of Proposed Rulemaking~~ , the " Bipartisan Permitting Reform Implementation Rule, " which ~~revises~~ **revised** the implementing regulations of the procedural provisions of NEPA and ~~implements~~ **implemented** the amendments to NEPA included in the June 3, 2023, Fiscal Responsibility Act of 2023. The final rule ~~is expected~~ **was challenged by various states and the litigation remains ongoing. More recently,** in **November** 2024 ~~. If any mining~~ , **the U. S. Court of Appeals** ~~or~~ **for the D. C. Circuit held** ~~oil and gas operations are subject to permitting requirements~~ that ~~trigger~~ **the CEQ lacks authority to issue** NEPA **regulations. As a result of this ruling and the recent change in the U. S. presidential administration and the following executive orders** , there is **significant** ~~likely to be some~~ uncertainty ~~about~~ **with respect to current and future requirements for** ~~the~~ **these analyses** ~~viability of any approvals that our lessees may obtain~~ . In November 2014, President Obama also announced an emission reduction agreement with China' s President Xi Jinping. The United States pledged that by 2025 it would cut climate pollution by 26 % to 28 % from 2005 levels. China pledged it would reach its peak carbon dioxide emissions around 2030 or earlier, and increase its non- fossil fuel share of energy to around 20 % by 2030. In December 2015, the United States was one of 196 countries that participated in the Paris Climate Conference, at which the participants agreed to limit their emissions in order to limit global warming to 2 ° C above pre- industrial levels, with an aspirational goal of 1. 5 ° C. ~~While~~ **In December 2023,** ~~there~~ -- **the United Arab Emirates hosted** ~~is no way to estimate the impact of these climate pledges and agreements, including, most recently,~~ the 28th session of the ~~United Nations~~ Conference of the Parties (" COP28") **where** ~~in December 2023, they could ultimately have an adverse effect on the demand for coal, both nationally and internationally, if implemented. In 2019, President Trump withdrew from the Paris Climate Agreement. On February 19, 2021, the United States officially rejoined the Paris Climate Agreement per President Biden' s order signed January 20. Additionally, at COP28, the~~ parties signed onto an agreement to transition " away from fossil fuels in energy systems in a just, orderly and equitable manner " and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for **doing so** ~~reaching net zero by that date~~ was set **. Subsequent Conferences have sought to build on the Paris Agreement by calling for various to phase out fossil fuels and subsidies related to the same, though none have been legally binding. The full impact of these actions is uncertain at this time, though these international agreements have the potential to result in increased pressure from financial institutions and other stakeholders to eliminate or reduce fossil fuel use and GHG emissions related to the same. Additionally, the new administration has re- withdrawn the United States from the Paris Agreement, and may make changes to the United States' participation in any of these programs, though the nature and timing of such changes are uncertain. Moreover, many states, regions, and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal- fired electric generating facilities, either as part of cap and trade, carbon tax, or climate " superfund " laws. For example, in December 2024, New York adopted a law requiring companies that emitted over 1 billion tons of GHG emissions into the atmosphere between 2000 and 2018, with sufficient connections to the state, to pay into a " climate superfund " to support climate- related adaptation and mitigation projects. Other states have announced their intent to increase the use of renewable energy sources, displacing coal and other fossil fuels. Depending on the particular regulatory program that may be enacted, at either the federal or state level, and the outcome of any legal challenges, the demand for coal and oil and gas could be negatively impacted, which would have an adverse effect on our operations. Many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG by certain facilities, including coal- fired electric generating facilities. For example, the RGGI calls for the implementation of a cap- and- trade program aimed at reducing carbon dioxide emissions from power plants in participating states. The members of RGGI have established in statutes and / or regulations a carbon dioxide trading program. Similar to RGGI, five western states launched the Western Regional Climate Initiative, although only California, Washington and Quebec are currently active participants. We cannot predict what other regional greenhouse gas reduction initiatives may arise in the future** . Hazardous Materials and Waste The Federal Comprehensive Environmental Response, Compensation and Liability Act (" CERCLA" or the Superfund law) and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered responsible for having contributed to the release of a " hazardous substance " into the environment. We could become liable under federal and state Superfund and waste management statutes if our lessees are unable to pay environmental cleanup costs relating to hazardous substances. In addition, we may have liability for environmental clean- up costs in connection with Sisecam Wyoming' s soda ash businesses **. The Resource Conservation and Recovery Act (" RCRA ") and analogous state laws impose requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non- hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by Surface Mining Control and Reclamation Act (" SMCRA ") permits are by statute exempted from RCRA permitting. Similarly, most wastes associated with the exploration, development, and production of oil & gas are exempt from regulation as hazardous wastes under RCRA, though these wastes typically constitute " solid wastes " that are subject to less stringent non- hazardous waste requirements. However, it is possible that RCRA could be amended or the EPA or state environmental agencies could adopt policies to require such wastes to become subject to more stringent storage, handling, treatment, or disposal requirements, which could impose significant additional costs on the operators of the properties in which we own coal or oil and gas interests. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on our operations. RCRA impacts the coal industry in particular because it regulates the disposal of certain CCB. On April 17, 2015, the EPA finalized regulations under RCRA for the disposal of CCB. Under the finalized regulations, CCB is regulated as " non- hazardous " waste and avoids the stricter, more costly, regulations under RCRA' s " hazardous " waste rules. While the classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our**

lessees’ operating costs and potentially reduce their ability to sell coal. The CCB rule was subject to legal challenge and ultimately remanded to the EPA. On August 28, 2020, the EPA published a final revised rule mandating the closure of unlined impoundments, with deadlines to initiate closure between 2021 and 2028, depending on site- specific circumstances. Certain provisions of the revised CCB rule were vacated by the D. C. Circuit in 2018. Meanwhile, on January 25, 2022, the EPA published determinations for 9 of 57 CCB facilities that sought approval to continue disposal of CCB and non- CCB waste streams until 2023, as opposed to the initial 2021 deadline for unlined impoundments prescribed by the current rule. While the EPA issued one conditional approval, the EPA required the remaining facilities to cease receipt of waste within 135 days of completion of public comment, or around July 2022. And, in January 2023, the EPA issued six proposed determinations to deny facilities’ requests to continue disposal into unlined surface impoundments. The current determinations, future determinations of the same nature, or similar actions in expected future rulemakings could lead to accelerated, abrupt, or unplanned suspension of coal- fired boilers. Most recently, in May 2024, the EPA finalized changes to the CCB regulations for inactive surface impoundments at inactive electric utilities in response to the D. C. Circuit’ s 2018 decision. The final rule expands the scope of impoundments subject to regulation and established groundwater monitoring, corrective action, closure, and post closure care requirements for all CCB management units. Although the rule has been challenged by industry groups, the U. S. Supreme Court rejected the challengers’ request to stay the rule so the rule remains effective as promulgated. The combined effect of the CCB rules and the ELG regulations (discussed below) has compelled power generating companies to close existing ash ponds and may force the closure of certain existing coal burning power plants that cannot comply with the new standards. Such retirements may adversely affect the demand for coal. On November 3, 2015, the EPA published the final rule ELG, revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technological improvements in the steam electric power industry over the last three decades. The EPA has from time to time updated the applicable ELG regulations and most recently, in May 2024, finalized a new ELG rule applicable to steam electric power generating facilities that sets new discharge limits for flue gas desulfurization wastewater, bottom ash transport water, combustion residual leachate, and legacy wastewaters. Although it is uncertain what actions the new administration may take regarding the 2024 ELG rule, to the extent the 2024 rule, which applies to a major portion of the electric power industry, remains in effect, it may impact the market for products in which we own a mineral interest . Water Discharges Operations conducted on our properties can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations create two permitting programs for mining operations. The National Pollutant Discharge Elimination System (" NPDES") program under Section 402 of the statute is administered by the states or EPA and regulates the concentrations of pollutants in discharges of waste and storm water from a mine site. The Section 404 program is administered by the Army Corps of Engineers and regulates the placement of overburden and fill material into channels, streams and wetlands that comprise “ waters of the United States. ” The scope of waters that may fall within the jurisdictional reach of the Clean Water Act is expansive and may include land features not commonly understood to be a stream or wetlands. The Clean Water Act and its regulations prohibit the unpermitted discharge of pollutants into such waters, including those from a spill or leak. Similarly, Section 404 also prohibits discharges of fill material and certain other activities in waters unless authorized by the issued permit. ~~In June~~ **Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the CWA. Rulemakings to establish the extent of such jurisdiction were finalized in** 2015 **and 2020** , **respectively, and both rulemakings were subject to substantial litigation. Although the** EPA ~~issued a new~~ **and Corps of Engineers did not seek to vacate the 2020** rule **on** ~~defining the scope of “ Waters of the United States ” (WOTUS) that are subject to regulation. The 2015 WOTUS rule was challenged by a number of states and~~ - **an** ~~private parties in~~ **interim basis, two** federal district ~~and circuit~~ courts **in Arizona and New Mexico vacated the 2020 rule in decisions announced during the third quarter of 2021** . In ~~December 2017~~ **January 2023** , **the** EPA and ~~the~~ Corps ~~proposed~~ **of Engineers published** a **final revised definition of** ~~rule to repeal the 2015~~ WOTUS **founded upon a** ~~rule and implement the~~ pre- 2015 definition ~~. The repeal of the 2015 WOTUS rule took effect in December 2019. In December 2018~~ , ~~EPA and the Corps issued a proposed rule again revising the definition of “ Waters of the United States. ” The new rule (the Navigable Waters Protection Rule) took effect in June 2020. In most of the pending legal challenges to the 2015 WOTUS rule, the petitioners filed amended complaints to include allegations challenging the 2020 rule. In January 2023, the EPA and the Army Corps of Engineers published a final revised definition of WOTUS founded upon a pre- 2015 definition and~~ including updates to incorporate existing Supreme Court decisions. **Following legal challenge** ~~Judicial developments further add~~ to ~~this uncertainty. In October 2022, the Supreme Court heard oral arguments in Sackett v. EPA regarding the scope and authority of the Clean Water Act and the definition of WOTUS and in May 2023, issued a ruling invalidating certain parts of~~ the January 2023 rule **and the Supreme Court’ s decision in Sackett v** . ~~A~~ **EPA, the EPA issued a** revised WOTUS rule ~~was issued~~ in September 2023. Due to the injunction in certain states, however, the implementation of the September 2023 rule currently varies by state **. The new Administration may seek to take additional action with respect to these regulations, although the substance and timing of such action cannot be predicted** . States issue a certificate pursuant to Clean Water Act Section 401 that is required for the Corps of Engineers to issue a Section 404 permit. In October 2021, the U. S. District Court for the Northern District of California vacated a 2020 rule revising the Section 401 certification process. The Supreme Court stayed this vacatur and, in September 2023, the EPA finalized its Clean Water Act Section 401 Water Quality Certification Improvement Rule, effective as of November 27, 2023. **The Water Quality Certification Improvement Rule was challenged by various states and a coalition of industry groups and the challenge remains ongoing.** While the full extent and impact of these actions is unclear at this time **due to the litigation and the new U. S. presidential administration** , any disruption in the ability to obtain required permits may result in increased costs and project delays. In connection with its review of permits, EPA has at times sought to reduce the size of fills and to impose limits on specific conductance (conductivity) and sulfate at levels that can be unachievable absent treatment at many mines. Such actions by EPA could make it more difficult or expensive to obtain or comply with such permits, which could, in turn, have an adverse effect on our coal- related revenues. In addition to government action, private citizens' groups have continued to be active in bringing lawsuits against operators and landowners. Since 2012, several citizen group lawsuits have been filed against mine operators for allegedly violating conditions in their National Pollutant Discharge Elimination System (" NPDES ") permits requiring compliance with West Virginia' s water quality standards. Some of the lawsuits alleged violations of water quality standards for selenium, whereas others alleged that discharges of conductivity and sulfate were causing violations of West Virginia' s narrative water quality standards, which generally prohibit adverse effects to aquatic life. The citizen suit groups have sought penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate. The federal district court for the Southern District of West Virginia has ruled in favor of the citizen suit groups in multiple suits alleging violations of the water quality standard for selenium and in two suits alleging violations of water quality standards due to discharges of conductivity (one of which was upheld on appeal by the United States Court of Appeals for the Fourth Circuit in January 2017). Additional rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for our lessees. In 2015, the West Virginia Legislature enacted certain changes to West Virginia' s NPDES program to expressly prohibit the direct enforcement of water quality standards against permit holders. EPA approved those changes as a program revision effective in March 2019. This approval may prevent future citizen suits alleging violations of water quality standards. Since 2013, several citizen group lawsuits have been filed against landowners alleging ongoing discharges of pollutants, including selenium and conductivity, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. Any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site could result in substantial compliance costs or fines and would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations. Endangered Species Act The federal Endangered Species Act (" ESA ") and counterpart state legislation protect species threatened with possible extinction. The U. S. Fish and Wildlife Service (" USFWS ") works closely with state regulatory agencies to ensure that species subject to the ESA are protected from potential impacts from mining- related and oil and gas exploration and production activities. In **recent years, there has been uncertainty with respect to ESA regulation. For example, in** October 2021, the Biden Administration proposed the rollback of new rules promulgated under the **first** Trump Administration and published an advanced notice of proposed rulemaking to codify a general prohibition on incidental take while establishing a process to regulate or permit exceptions to such a prohibition. ~~In February 2023, the USFWS published a proposed rule that revised the requirements for an incidental take permit application. A final rule is scheduled for release in 2024.~~ Additionally, in June 2022, the USFWS and the National Marine Fisheries Service **(" NMFS ")** published a final rule rescinding the 2020 regulatory definition of " habitat. " **Most recently, in April 2024, the USFWS and NMFS finalized three rules that revise regulations for classifying species and designating critical habitat, interagency cooperation, and protecting endangered and threatened species. Among other things, these rules reinstate prior language affirming that listing determinations are made " without reference to possible economic or other impacts of such determination, " clarify the standards for delisting species, revise the set of circumstances for when critical habitat may be not prudent, revise the criteria for identifying unoccupied critical habitat, and reinstate the general application of the " blanket rule " option for protecting newly listed threatened species. We cannot predict what actions the new administration may take with respect to these regulations and the timing with respect to the same. As a result, there is significant uncertainty with respect to ESA regulation at this time.** If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered or to redesignate a species from threatened to endangered, we or the operators of the properties in which we hold oil and gas or mineral interests could be subject to additional regulatory and permitting requirements, which in turn could increase operating costs or adversely affect our revenues. Other Regulations Affecting the Mining Industry Mine Health and Safety Laws The operations of our coal lessees and Sisecam Wyoming are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease. Mining accidents in recent years have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. Since 2006, heightened scrutiny has been applied to the safe operations of both underground and surface mines. This increased level of review has resulted in an increase in the civil penalties that mine operators have been assessed for non- compliance. Operating companies and their supervisory employees have also been subject to criminal convictions. The Mine Safety and Health Administration (" MSHA") has also advised mine operators that it will be more aggressive in placing mines in the Pattern of Violations program, if a mine' s rate of injuries or significant and substantial citations exceed a certain threshold. A mine that is placed in a Pattern of Violations program will receive additional scrutiny from MSHA. **MSHA has also published, and may continue to publish, requests for information on various mining topics that may result in additional rules applicable to our operations and the operations of our lessees. Recent requests include topics such as engineering controls and best practices to lower miners' exposure to respirable coal mine dust and exposure of underground miners to diesel exhaust. Recent MSHA rulemaking actions include, for example: ● In April 2024, MSHA adopted a rule on respirable crystalline silica, most commonly found in the mining environment through**

quartz. The final rule, which took effect on June 17, 2024, amends the existing MSHA standards to lower the permissible exposure limit of respirable crystalline silica, as well as set forth new or revised standards for exposure sampling, corrective actions, medical surveillance for metal and non- metal miners, and respiratory protection requirements. ● In December 2024, MSHA adopted a rule to revise Testing, Evaluation, and Approval of Electric Motor- Driven Mine Equipment and Accessories within underground mining environments. The final rule, effective January 9, 2025, adopts various voluntary consensus standards to promote innovation in mine safety and health technologies. ● In December 2023, MSHA published a final rule, which took effect on January 19, 2024, requiring that mine operators and independent contractors operating mobile equipment develop, implement, and periodically update a written safety program for surface mobile equipment (excluding belt conveyors) at surface mines and surface areas of underground mines. The deadline for compliance with the rule was July 17, 2024. MSHA has also finalized a number of rules related to controlling exposure to coal mine dust, which has resulted in progressively stricter exposure limits imposed by MHSA regulations. These requirements impose a number of dust monitoring obligation and mine ventilation requirements on our coal lessees' operations. Compliance with these rules can result in increased costs on our lessees' operations, including, but not limited to, the purchasing of new equipment and the hiring of additional personnel to assist with monitoring, reporting, and recordkeeping obligations. It is uncertain whether any of the above or other various proposed rules or requests for information would have material impacts on our operations, our costs of operation, or the operations of our lessees. Surface Mining Control and Reclamation Act of 1977 The Surface Mining Control and Reclamation Act of 1977 (" SMCRA") and similar statutes enacted and enforced by the states impose on mine operators the responsibility of reclaiming the land and compensating the landowner for types of damages occurring as a result of mining operations. To ensure compliance with any reclamation obligations, mine operators are required to post performance bonds. Our coal lessees are contractually obligated under the terms of our leases to comply with all federal, state and local laws, including SMCRA. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the reclamation plan approved by the state regulatory authority. In addition, higher and better uses of the reclaimed property are encouraged. Mining Permits and Approvals Numerous governmental permits or approvals such as those required by SMCRA and the Clean Water Act are required for mining operations. In connection with obtaining these permits and approvals, our lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations. In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including our lessees, must submit a reclamation plan for reclaiming the mined property upon the completion of mining operations. ~~Our~~ **The majority of our** lessees have obtained or applied for permits to mine a ~~majority~~ **significant portion** of ~~the~~ **its** coal that is currently planned to be mined over the next five years ~~. Our lessees are also~~ **, and continue to be** in the planning phase for obtaining permits for the additional coal planned to be mined over the following five years. However, given the imposition of new requirements in the permits in the form of policies and the increased oversight review that has been exercised by EPA, there are no assurances that they will not experience difficulty and delays in obtaining mining permits in the future. In addition, EPA has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators. Employees and Labor Relations As of December 31, ~~2023~~ **2024** , affiliates of our general partner employed ~~55~~ **54** people who directly supported our operations. None of these employees were subject to a collective bargaining agreement. Human Capital We believe all individuals are entitled to courtesy, dignity, and respect, and we support a culture of integrity and personal and professional growth. We are strong leaders within our community, and we seek to uphold a positive presence in all areas where we live and work. Website Access to Partnership Reports Our internet address is www. nrplp. com. We make available free of charge on or through our website 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 pursuant to Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Information on our website is not a part of this report. In addition, the SEC maintains a website at www. sec. gov that contains reports, proxy and information statements and other information filed by us. Corporate Governance Matters Our Code of Business Conduct and Ethics, our Disclosure Controls and Procedures Policy and our Corporate Governance Guidelines adopted by the Board of Directors, as well as the charter for our Audit Committee **and Compensation, Nominating and Governance Committee** are available on our website at www. nrplp. com. Copies of our annual report, our Code of Business Conduct and Ethics, our Disclosure Controls and Procedures Policy, our Corporate Governance Guidelines and our committee charters will be made available upon written request to our principal executive office at 1415 Louisiana St., Suite 3325, Houston, Texas 77002. ITEM 1A. RISK FACTORS Because distributions on the common units are dependent on the amount of cash we generate, distributions fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter depends on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, and not solely on profitability, which is affected by non- cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits. The actual amount of cash we have to distribute each quarter is reduced by payments in respect of debt service and other contractual obligations, ~~including distributions on the preferred units,~~ fixed charges, maintenance capital expenditures, and reserves for future operating or capital needs that the Board of Directors may determine are appropriate. We have significant debt service obligations ~~and obligations to pay cash distributions on our preferred units~~ . To the extent our Board of Directors deems appropriate, it may determine to decrease the amount of the quarterly distribution on our common units or suspend or eliminate the distribution on our common units altogether. In addition, because our unitholders are required to pay income taxes on their respective shares of our taxable income, our unitholders may be required to pay taxes in excess of any future distributions we make. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities. See" — Tax Risks to Our Unitholders — Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities." Our partnership agreement requires our consolidated leverage ratio to be less than 3. 25x in order to make quarterly distributions on the common units in an amount in excess of $ 0. 45 per unit. For more information on restrictions on our ability to make distributions on our common units, see" Item 7. Management' s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" and" Item 8. Financial Statements and Supplementary Data — Note 11. Debt, Net." As of December 31, ~~2023~~ **2024** , we and our subsidiaries had approximately $ ~~155~~ **142** . ~~5~~ **3** million of total indebtedness. The terms and conditions governing the indenture for Opco' s revolving credit facility and senior notes: • require us to meet certain leverage and interest coverage ratios; • require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industries in which we operate; • increase our vulnerability to economic downturns and adverse developments in our business; • limit our ability to access the bank and capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness; • place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations; • place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; • make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations; and • limit management' s discretion in operating our business. Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations ~~, including payment of distributions on the preferred units~~ . If we do not have sufficient funds, we may be required to refinance all or part of our existing debt, borrow more money, or sell assets or raise equity at unattractive prices, including higher interest rates. We are required to make substantial principal repayments each year in connection with Opco' s senior notes, with approximately $ ~~31~~ **14** million due thereunder during ~~2024~~ **2025** . To the extent we borrow to make some of these payments, we may not be able to refinance these amounts on terms acceptable to us, if at all. We may not be able to refinance our debt, sell assets, borrow more money or access the bank and capital markets on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our debt agreements will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations. Global pandemics ~~, including the COVID- 19 pandemic~~ have in the past and may continue to adversely affect our business. The COVID- 19 pandemic adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities and global trading markets. Coal markets faced substantial challenges prior to the pandemic, and widespread increases in unemployment and decreases in electricity and steel demand further reduced demand and prices for coal in 2020. In addition, demand for and prices of soda ash decreased in 2020, as global manufacturing slowed. Our Board of Directors determined to suspend cash distributions to our common unitholders with respect to the first quarter of 2020 in order to preserve liquidity due to uncertainties created by the pandemic. In addition, Sisecam Wyoming suspended cash distributions to its members in 2020 due to adverse effects of the pandemic on the global and domestic soda ash markets. Both companies have resumed distributions, however there remains a risk that distributions could be suspended in the future due to another global pandemic. Coal prices continue to be volatile and prices could decline substantially from current levels. Production by some of our lessees may not be economic if prices decline further or remain at current levels. The prices our lessees receive for their coal depend upon factors beyond their or our control, including: • the supply of and demand for domestic and foreign coal; • domestic and foreign governmental regulations and taxes; • changes in fuel consumption patterns of electric power generators; • the price and availability of alternative fuels, especially natural gas; • global economic conditions, including the strength of the U. S. dollar relative to other currencies; • global and domestic demand for steel; • tariff rates on imports and trade disputes, particularly involving the United States and China; • the availability of, proximity to and capacity of transportation networks and facilities; • global or national health concerns, including the outbreak of pandemic or contagious disease ~~, such as the COVID- 19 pandemic~~ ; • weather conditions; and • the effect of worldwide energy conservation measures. Natural gas is the primary fuel that competes with thermal coal for power generation, and renewable energy sources continue to gain market share in power generation. The abundance and ready availability of cheap natural gas, together with increased governmental regulations on the power generation industry has caused a number of utilities to switch from thermal coal to natural gas and / or close coal- powered generation plants. This switching has resulted in a decline in thermal coal prices, and to the extent that natural gas prices remain low, thermal coal prices will also remain low. Reduced international demand for export thermal coal and increased competition from global producers has also put downward pressure on thermal coal prices. Our lessees produce a significant amount of metallurgical coal that is used for steel production domestically and internationally. Since the amount of steel that is produced is tied to global economic conditions, declines in those conditions could result in the decline of steel, coke and metallurgical coal production. Since metallurgical coal is priced higher than thermal coal, some mines on our properties may only operate profitably if all or a portion of their production is sold as metallurgical coal. If these mines are unable to sell metallurgical coal, they may not be economically viable and may be temporarily idled or closed. Any potential future lessee bankruptcy filings could create additional uncertainty as to the future of operations on our properties and could have a material adverse effect on our business and results of operations. To the extent our lessees are unable to economically produce coal over the long term, the carrying value of our coal mineral rights could be adversely affected. A long- term asset generally is deemed impaired when the future expected cash flow from its use and disposition is less than its book value. For the year ended December 31, ~~2023~~ **2024** , we recorded impairment charges of approximately $ 0. ~~6~~ **1** million related to properties that we believe our current or future lessees are unable to operate profitably. Future impairment analyses could result in additional downward adjustments to the carrying value of our assets **. Restrictions on international trade, such as sanctions, tariffs, duties and other governmental controls on imports or exports of goods, could adversely affect our business. In February 2025, the U. S. presidential administration imposed new tariffs on China and China responded with tariffs on select U. S. goods, including coal, which could negatively affect the price of coal. If new legislation or additional trade restrictions are adopted or geopolitical tensions were to increase and reduce the price received by our lessees for coal sales, the amount of royalties that we receive from our lessees would also be reduced which could adversely affect our free cash flow** . Prices for soda ash are volatile. Any substantial or extended decline in soda ash prices could have an adverse effect on Sisecam Wyoming' s ability to continue to make distributions to its members and on our results of operations. The market price of soda ash directly affects the profitability of Sisecam Wyoming' s soda ash production operations. If the market price for soda ash declines, Sisecam Wyoming' s sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash has been volatile, and those markets are likely to remain volatile in the future. The prices Sisecam Wyoming receives for its soda ash depend on numerous factors beyond Sisecam Wyoming' s control, including worldwide and regional economic and political conditions impacting supply and demand. In addition, the impact of the Sisecam Chemicals Resources' exit from ANSAC and Sisecam Wyoming' s transition to the utilization of Sisecam Group' s global distribution network for some of its export operations beginning 2021 could affect prices received for export sales. Glass manufacturers and other industrial customers drive most of the demand for soda ash, and these customers experience significant fluctuations in demand and production costs. Competition from increased use of glass substitutes, such as plastic and recycled glass, has had a negative effect on demand for soda ash. Substantial or extended declines in prices for soda ash could have a material adverse effect on Sisecam Wyoming' s ability to continue to make distributions to its members and on our results of operations. Challenges in the coal mining industry have led to significant consolidation activity. We own significant interests in several of Alpha' s mining operations, which accounted for approximately ~~23~~ **28** % of our total revenues in ~~2023~~ **2024** . We also own significant interests in all of Foresight' s mining operations, which accounted for approximately 16 % of our total revenues in ~~2023~~ **2024 . We also own a significant interest in Alabama Kanu' s Oak Grove operation, which accounted for approximately 12 % of our total revenues in 2024** . Certain other lessees have made acquisitions over the past few years resulting in their having an increased interest in our coal. Any interruption in these lessees' ability to make royalty payments to us could have a disproportionate material adverse effect on our business and results of operations. While current coal prices have recovered substantially, the recent coal price environment, together with high operating costs and limited access to capital, has caused a number of coal producers to file for protection under The U. S. Bankruptcy Code and / or idle or close mines that they cannot operate profitably. To the extent our leases are accepted or assigned in a bankruptcy process, pre- petition amounts are required to be cured in full, but we may ultimately make concessions in the financial terms of those leases in order for the reorganized company or new lessor to operate profitably going forward. To the extent our leases are rejected, operations on those leases will cease, and we will be unlikely to recover the full amount of our rejection damages claims. More of our lessees may file for bankruptcy in the future, which will create additional uncertainty as to the future of operations on our properties and could have a material adverse effect on our business and results of operations. Our revenues are largely dependent on the level of production of minerals from our properties, and any interruptions to or increases in costs of the production from our properties may reduce our revenues. The level of production and costs thereof are subject to operating conditions or events beyond our or our lessees' control including: • difficulties or delays in acquiring necessary permits or mining or surface rights; • reclamation costs and bonding costs; • changes or variations in geologic conditions, such as the thickness of the mineral deposits and the amount of rock embedded in or overlying the mineral deposit; • mining and processing equipment failures and unexpected maintenance problems; • the availability of equipment or parts and increased costs related thereto; • the availability of transportation networks and facilities and interruptions due to transportation delays; • adverse weather and natural disasters, such as heavy rains and flooding; • labor- related interruptions and trained personnel shortages; and • mine safety incidents or accidents, including hazardous conditions, roof falls, fires and explosions. While our lessees maintain insurance coverage, there is no assurance that insurance will be available or cover the costs of these risks. Many of our lessees are experiencing rising costs related to regulatory compliance, insurance coverage, permitting and reclamation bonding, transportation, and labor. Increased costs result in decreased profitability for our lessees and reduce the competitiveness of coal as a fuel source. In addition, we and our lessees may also incur costs and liabilities resulting from third- party claims for damages to property or injury to persons arising from their operations. The occurrence of any of these events or conditions could have a material adverse effect on our business and results of operations. Enactment of laws and passage of regulations regarding emissions from the combustion of coal by the U. S., some of its states or other countries, or other actions to limit such emissions, have resulted in and could continue to result in electricity generators switching from coal to other fuel sources and in coal- fueled power plant closures. Further, regulations regarding new coal- fueled power plants could adversely impact the global demand for coal. The potential financial impact on us of existing and future laws, regulations or other policies will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants and environmental and other governmental regulations. We expect that substantially all newly constructed power plants in the United States will be fired by natural gas because of lower construction and compliance costs compared to coal- fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of rules and regulations promulgated under the federal Clean Air Act have resulted in more electric power generators shifting from coal to natural- gas- fired power plants, or to other alternative energy sources such as solar and wind. These changes have resulted in reduced coal consumption and the production of coal from our properties and are expected to continue to have an adverse effect on our coal- related revenues. In addition to EPA' s greenhouse gas initiatives, there are several other federal rulemakings that are focused on emissions from coal- fired electric generating facilities, including the Cross- State Air Pollution Rule (" CSAPR") as revised in 2021, regulating emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (" MATS"), regulating emissions of hazardous air pollutants. Installation of additional emissions control technologies and other measures required under these and other EPA regulations have made it more costly to operate many coal- fired power plants and have resulted in and are expected to continue to result in plant closures. Further reductions in coal' s share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal- related revenues. For more information on regulation of greenhouse gas and other air pollutant emissions, see" Items 1. and 2. Business and Properties — Regulation and Environmental Matters. " Global climate issues continue to attract public and scientific attention. Numerous reports have engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In addition to government regulation of greenhouse gas and other air pollutant emissions, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuels, such as coal. One example is the Net Zero Banking Alliance, a group of over 100 banks worldwide representing over 40 % of global banking assets who are committed to aligning their investment portfolios with net zero emissions by 2050. Further, in October 2023, the Federal Reserve, Office of the Comptroller of the Currency and the Federal Deposit Insurance Corp. released a finalized set of principles guiding financial institutions with $ 100 billion or more in assets on the management of physical and transition risks associated with climate change. **Although, the future of these principles is uncertain in the new U. S. presidential administration.** The impact of such efforts may adversely affect our ability to raise capital. In addition, a number of insurance companies have taken action to limit coverage for companies in the coal industry, which could result in significant increases in our costs of insurance or in our inability to maintain insurance coverage at current levels. Increasing attention to climate change, societal expectations on companies to address climate change, and investor and societal expectations regarding ESG matters and disclosures, may result in increased costs, reduced profits, increased investigations and litigation, and negative impacts on our access to capital ~~. The SEC has also announced that it is scrutinizing existing climate- change related disclosures in public filings, increasing the potential for enforcement~~ . Any laws or regulations imposing more stringent requirements on our business related to the disclosure of climate related risks may increase compliance costs, and result in potential restrictions on access to capital to the extent we do not meet any climate- related expectations or requirements of financial institutions. ~~The possible promulgation later~~ **Additionally, the SEC released its final rule on climate- related disclosures on March 6, 2024, requiring the disclosure of certain climate- related risks and financial impacts, as well as greenhouse gas emissions. Under the rule, large accelerated filers would be required to incorporate the applicable climate- related disclosures into their filings beginning in fiscal year 2025, with additional requirements relating to the disclosure of Scope 1 and 2 greenhouse gas emissions, if material, and attestation reports for certain large accelerated filers subsequently phasing in. However, the future of the SEC climate rule is uncertain at** this ~~year by~~ **time given that its implementation has been stayed pending the outcome of legal challenges; moreover, it is uncertain whether the Commission may seek to change or revoke the rule though we cannot predict whether such action will occur or its timing. As a result, the ultimate impact of** the SEC ~~of additional reporting~~ **rule, or any similar climate- related disclosure** requirements **imposed in the future** ~~for registrants regarding climate risks~~ , ~~targets~~ **on our business is uncertain** and ~~metrics~~ may ~~add to the cost of preparing filings and could~~ result in ~~additional disclosures that may further~~ **increased compliance costs and increased costs of and** ~~restrict~~ **restrictions** ~~our~~ **on** access to capital. Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters, and many of these ratings processes are inconsistent with each other. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy- related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital. Furthermore, if our competitors' ESG performance is perceived to be greater than ours, potential or current investors may elect to invest in our competitors instead. **In addition to climate change and other Clean Air Act legislation, our businesses are subject to numerous other federal, state and local laws and regulations that may limit production from our properties and our profitability. Thus, any changes in environmental laws and regulations or reinterpretations of enforcement policies, or in presidential administrations, that result in more stringent or costly obligations could adversely affect our performance.** The operations of our lessees and Sisecam Wyoming are subject to stringent health and safety standards under increasingly strict federal, state and local environmental, health and safety laws, including mine safety regulations and governmental enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our properties. New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements **, or changes in presidential administrations** , could further regulate or tax mining industries and may also require significant changes to operations, the incurrence of increased costs or the requirement to obtain new or different permits, any of which could decrease our revenues and have a material adverse effect on our financial condition or results of operations. Under SMCRA, our coal lessees have substantial reclamation obligations on properties where mining operations have been completed and are required to post performance bonds for their reclamation obligations. To the extent an operator is unable to satisfy its reclamation obligations or the performance bonds posted are not sufficient to cover those obligations, regulatory authorities or citizens groups could attempt to shift reclamation liability onto the ultimate landowner, which if successful, could have a material adverse effect on our financial condition. In addition to governmental regulation, private citizens' groups have continued to be active in bringing lawsuits against coal mine operators and land owners that allege violations of water quality standards resulting from ongoing discharges of pollutants from reclaimed mining operations, including selenium and conductivity. Any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations and could result in substantial compliance costs or fines. For more information on regulation of greenhouse gas and other air pollutant emissions, see" Items 1. and 2. Business and Properties — Regulation and Environmental Matters. " We depend on our lessees to effectively manage their operations on our properties. Our lessees make their own business decisions with respect to their operations within the constraints of their leases, including decisions relating to: • the payment of minimum royalties; • marketing of the minerals mined; • mine plans, including the amount to be mined and the method and timing of mining activities; • processing and blending minerals; • expansion plans and capital expenditures; • credit risk of their customers; • permitting; • insurance and surety bonding; • acquisition of surface rights and other mineral estates; • employee wages; • transportation arrangements; • compliance with applicable laws, including environmental laws; and • mine closure and reclamation. A failure on the part of one of our lessees to make royalty payments, including minimum royalty payments, could give 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 lessee. We might not be able to find a replacement lessee 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 existing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If we enter into a new lease, the replacement operator might not achieve the same levels of production or sell minerals at the same price as the lessee it replaced. In addition, it may be difficult for us to secure new or replacement lessees. We do not have control over the operations of Sisecam Wyoming. We have limited approval rights with respect to Sisecam Wyoming, and our partner controls most business decisions, including decisions with respect to distributions and capital expenditures. During 2020, Sisecam Wyoming suspended cash distributions to its members due to adverse developments in the soda ash market resulting from the COVID- 19 pandemic. Distributions resumed in 2021 but no assurance can be made that additional suspensions will not occur in the future. ~~In December 2021, the parent of the 51 % owner of Sisecam Wyoming sold 60 % of its interest to~~ Sisecam Chemicals USA Inc., a wholly owned subsidiary of Türkiye Şişe ve Cam Fabrikalari A. Ş ~~. As a result of the transaction~~ , **appoints four of the seven Board of Managers of Sisecam Wyoming and** we ~~will continue to~~ appoint three ~~of the seven Board of Managers of Sisecam Wyoming, Sisecam USA will appoint three and Ciner Enterprises Inc. will appoint one~~ . Any changes to the distribution policy or the capital expenditure plans approved by the ~~newly constituted~~ Board of Managers could adversely affect the future cash flows to NRP and the financial condition and results of operations of Sisecam Wyoming. In addition, we are ultimately responsible for operating the transportation infrastructure at Foresight' s Williamson mine, and have assumed the capital and operating risks associated with that business. As a result of these investments, we could experience increased costs as well as increased liability exposure associated with operating these facilities. Sisecam Wyoming ~~'~~ **'** s ~~deca stockpiles will~~ **reserve and resource estimates may vary** substantially **from the actual amounts of minerals** ~~deplete by 2024 and its production rates will decline if~~ Sisecam Wyoming **is able** ~~does not make further investments or otherwise execute on one or more initiatives~~ to ~~prevent such decline~~ **recover economically from their reserves** . **There are numerous uncertainties inherent in estimating quantities of reserves** ~~In 2024, Sisecam Wyoming' s deca stockpiles will be substantially depleted~~ and **resources, including many factors beyond** Sisecam Wyoming' s **control. Estimates of reserves and resources necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to, among other aspects: • future prices of soda ash, mining and** production ~~rates will decline~~ **costs, capital expenditures and transportation costs; • future mining technology and processes; • the effects of regulation by governmental agencies; and • geologic and mining conditions** , which ~~would impact~~ **may not be identified by available exploration data and may differ from** Sisecam Wyoming' s ~~profitability~~ **experiences in areas where it currently mines** . ~~While~~ **Please read Items 1 and 2. " Business and Properties — Trona Resources and Trona Reserves " for more information including pertinent additional assumptions regarding** Sisecam Wyoming **' s reserve estimates in** ~~is currently evaluating whether and when to pursue one or more initiatives that could offset~~ this **Report. Actual** ~~decline as well as provide additional soda ash~~ production ~~above current rates~~ , **revenue and expenditures with respect** ~~there is no guarantee that any such initiatives or investments will be executed successfully, in a timely manner, or if at all~~ to ~~enable~~ Sisecam Wyoming ~~to maintain its current rates of production~~ **' s reserves will likely vary from their estimates, and these variations may be material** . Transportation costs represent a significant portion of the total delivered cost for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make minerals produced by some or all of our lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for our lessees from producers in other parts of the country. Our lessees depend upon railroads, barges, trucks and beltlines to deliver minerals to their customers. Disruption of those transportation services due to weather- related problems, mechanical difficulties, strikes, lockouts, bottlenecks and / or other events could temporarily impair the ability of our lessees to supply coal to their customers and / or increase their costs. Many of our lessees are currently experiencing transportation- related issues due in particular to decreased availability and reliability of rail services and port congestion. Our lessees' transportation providers may face difficulties in the future that would impair the ability of our lessees to supply minerals to their customers, resulting in decreased royalty revenues to us. In addition, Sisecam Wyoming transports its soda ash by rail or truck and ocean vessel. As a result, its business and financial results are sensitive to increases in rail freight, trucking and ocean vessel rates. Increases in transportation costs, including increases resulting from emission control requirements, port taxes and fluctuations in the price of fuel, could make soda ash a less competitive product for glass manufacturers when compared to glass substitutes or recycled glass, or could make Sisecam Wyoming' s soda ash less competitive than soda ash produced by competitors that have other means of transportation or are located closer to their customers. Sisecam Wyoming may be unable to pass on its freight and other transportation costs in full because market prices for soda ash are generally determined by supply and demand forces. In addition, rail operations are subject to various risks that may result in a delay or lack of service at Sisecam Wyoming' s facility, and alternative methods of transportation are impracticable or cost prohibitive. For the year ended December 31, ~~2023~~ **2024**, Sisecam Wyoming shipped over 90 % of its soda ash from the Green River facility on a single rail line owned and controlled by Union Pacific. Any substantial interruption in or increased costs related to the transportation of Sisecam Wyoming' s soda ash or the failure to renew the rail contract on favorable terms could have a material adverse effect on our financial condition and results of operations. Mineral supply contracts generally do not require operators to satisfy their obligations to their customers with resources mined from specific locations. Several factors may influence a lessee' s decision to supply its customers with minerals mined from properties we do not own or lease, including the royalty rates under the lessee' s lease with us, mining conditions, mine operating costs, cost and availability of transportation, and customer specifications. In addition, lessees move on and off of our properties over the course of any given year in accordance with their mine plans. If a lessee satisfies its obligations to its customers with minerals from properties we do not own or lease, production on our properties will decrease, and we will receive lower royalty revenues. We depend on our lessees to correctly report production and royalty revenues on a monthly basis. Our regular lessee audits and mine inspections may not discover any irregularities in these reports or, if we do discover errors, we might not identify them in the reporting period in which they occurred. Any undiscovered reporting errors could result in a loss of royalty revenues and errors identified in subsequent periods could lead to accounting disputes as well as disputes with our lessees. Our managing general partner manages and operates NRP. Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the Board of Directors on an annual or any other basis. Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 66 2 / 3 % of our outstanding common units (including common units held by our general partner and its affiliates ~~and including common units deemed to be held by the holders of the preferred units who vote along with the common unitholders on an as- converted basis~~). Because of their substantial ownership in us, the removal of our general partner would be difficult without the consent of ~~both~~ our general partner and its affiliates ~~and the holders of the preferred units~~. In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management: • generally, if a person ~~(other than the holders of preferred units)~~ acquires 20 % or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and • our partnership agreement contains limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management. As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price. **We may issue additional** ~~The preferred units rank senior to our~~ common units ~~with respect to distribution rights and rights upon liquidation. We are required to pay quarterly distributions on the preferred units (plus any PIK units issued in lieu of preferred units) in an amount equal to 12. 0 % per year prior to paying any distributions on our~~ - **or other equity securities without** common **unitholder approval** ~~units. The preferred units also rank senior to the common units in right of liquidation and will be entitled to receive a liquidation preference in any such case. The preferred units may also be converted into common units under certain circumstances. The number of common units issued in any conversion will be based on the then- current trading price of the common units at the time of conversion. Accordingly, the lower the trading price of our common units at the time of conversion, the greater the number of common units that will be issued upon conversion of the preferred units~~ , which ~~would~~ **could dilute a** ~~result in greater dilution to our existing common unitholders. Dilution has the following effects on our common unitholders: • an existing~~ unitholder' s ~~proportionate~~ **existing** ownership ~~interest~~ **interests** ~~in NRP will decrease; • the amount of cash available for distribution on each unit may decrease; • the relative voting strength of each previously outstanding unit may be diminished; and • the market price of the common units may decline. In addition, to the extent the preferred units are converted into more than 66 2 / 3 % of our common units, the holders of the preferred will have the right to remove our general partner~~. Our general partner may cause us to issue an unlimited number of common units, without common unitholder approval (subject to applicable New York Stock Exchange (" NYSE") rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units ~~(including additional preferred units)~~ without common unitholder approval (subject to applicable NYSE rules). ~~In addition, we may issue additional common units upon the exercise of the outstanding warrants held by Blackstone.~~ The issuance of additional common units or other equity securities of equal or senior rank will have the following effects: **• an existing unitholder' s proportionate ownership interest in NRP will decrease;** • the amount of cash available for distribution on each unit may decrease; ~~and~~ • the relative voting strength of each previously outstanding unit may be diminished; and **•** the market price of the common units may decline. If at any time our general partner and its affiliates own 80 % or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units. Prior to making any distribution on the common units, we reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner. These conflicts may include the following: • ~~We~~ **we** do not have any employees and we rely solely on employees of affiliates of the general partner; • under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership; • the amount of cash expenditures, borrowings and reserves in any quarter may affect cash available to pay quarterly distributions to unitholders; • the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner' s liability; • under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arm' s- length negotiations; and • the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us. ~~In addition, GoldenTree also has certain limited consent rights. In the exercise of their applicable consent rights, conflicts of interest could arise between us and our general partner on the one hand, and GoldenTree on the other hand.~~ Our general partner may 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. Furthermore, there is no restriction in our partnership agreement on the ability of the managing general partner from transferring its general partnership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board of Directors and officers with its own choices and to control their decisions and actions. In addition, a change of control would constitute an event of default under our debt agreements. During the continuance of an event of default under our debt agreements, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us and / or declare all amounts payable by us immediately due and payable ~~. In addition, upon a change of control, the holders of the preferred units would have the right to require us to redeem the preferred units at the liquidation preference or convert all of their preferred units into common units~~. A change of control also may trigger payment obligations under various compensation arrangements with our officers. Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Under Delaware law, however, a unitholder 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. In addition, Section 17- 607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution. The anticipated after- tax economic benefit of an investment in our units depends largely on our being treated as a partnership for U. S. 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 on our current operations and current Treasury Regulations, 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. Failing to meet the qualifying income requirement 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 U. S. federal income tax purposes, we would pay U. S. federal income tax on our taxable income at the corporate tax rate and would likely be liable for state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation 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 units. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. We currently own assets and conduct business in several states, many of which impose a margin or franchise tax. In the future, we may expand our operations. Imposition of a similar tax on us in a jurisdiction in which we operate or in other jurisdictions to which we may expand could substantially reduce the cash available for distribution to our unitholders. The present U. S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U. S. federal income tax laws that would affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for partnership tax treatment. Recent proposals have provided for the expansion of the qualifying income exception for publicly traded partnerships in certain circumstances and other proposals have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment. Further, while unitholders of publicly traded partnerships are, subject to certain limitations, entitled to a deduction equal to 20 % of their allocable share of a publicly traded partnership' s " qualified business income, " this deduction is scheduled to expire with respect to taxable years beginning after December 31, 2025. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U. S. 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 in the future. Any modification to the U. S. 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 meet the exception for certain publicly traded partnerships to be treated as partnerships for U. S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our units. Changes to U. S. federal income tax laws have been proposed in a prior session of Congress that would eliminate certain key U. S. federal income tax preferences relating to coal exploration and development. These changes include, but are not limited to (i) repealing capital gains treatment of coal and lignite royalties, (ii) eliminating current deductions and 60-month amortization for exploration and development costs relating to coal and other hard mineral fossil fuels, and (iii) repealing the percentage depletion allowance with respect to coal properties. If enacted, these changes would limit or eliminate certain tax deductions that are currently available with respect to coal exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units. Because our unitholders are treated as partners to whom we allocate taxable income that could be different in amount than the cash we distribute, our unitholders are required to pay any U. S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due from them with respect to that income. For our unitholders subject to the passive loss rules, our current operations include portfolio activities (such as our coal and mineral royalty businesses) and passive activities (such as our soda ash business). Any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset (i) our portfolio income, including income related to our coal and mineral royalty businesses, (ii) a unitholder’ s income from other passive activities or investments, including investments in other publicly traded partnerships, or (iii) a unitholder’ s salary or active business income. Thus, our unitholders' share of our portfolio income may be subject to U. S. federal income tax, regardless of other losses they may receive from us. We may engage in transactions to reduce our leverage and manage our liquidity that would result in income and gain to our unitholders without a corresponding cash distribution. For example, we may sell assets and use the proceeds to repay existing debt, in which case, our unitholders could be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, we may pursue opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt that would result in “ cancellation of indebtedness income ” (also referred to as “ COD income ”) being allocated to our unitholders as ordinary taxable income. Our unitholders may be allocated income and gain from these transactions, and income tax liabilities arising therefrom may exceed any distributions we make to our unitholders. The ultimate tax effect of any such income allocations will depend on the unitholder' s individual tax position, including, for example, the availability of any suspended passive losses that may offset some portion of the allocable income. Our unitholders may, however, be allocated substantial amounts of ordinary income subject to taxation, without any ability to offset such allocated income against any capital losses attributable to the unitholder’ s ultimate disposition of its units. Our unitholders are encouraged to consult their tax advisors with respect to the consequences to them. We have not requested a ruling from the IRS with respect to our treatment as a partnership for U. S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest by the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest by the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution. If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments 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, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustments into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Distributions in excess of a common unitholder' s allocable share of our net taxable income result in a decrease in the tax basis in such unitholder' s common units. Accordingly, the amount, if any, of such prior excess distributions with respect to the common units sold will, in effect, become taxable income to our common unitholders if they sell such common units at a price greater than their tax basis in those common units, even if the price they receive is less than their original cost. In addition, because the amount realized includes a unitholder’ s share of our nonrecourse liabilities, if our unitholders sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale. A substantial portion of the amount realized from a unitholder’ s sale of our units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder’ s adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $ 3, 000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units. In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, our deduction for “ business interest ” is limited to the sum of our business interest income and 30 % of our “ adjusted taxable income. ” For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income. If our “ business interest ” is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us. Investment in our units by tax- exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U. S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Additionally, all or part of any gain recognized by such tax- exempt organization upon a sale or other disposition of our units may be unrelated business taxable income and may be taxable to them. Tax- exempt entities should consult a tax advisor before investing in our units. Non- U. S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U. S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be “ effectively connected ” with a U. S. trade or business. As a result, distributions to a non- U. S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non- U. S. unitholder who sells or otherwise disposes of a unit will also be subject to U. S. federal income tax on the gain realized from the sale or disposition of that unit. In addition to the withholding tax imposed on distributions of effectively connected income, distributions to a non- U. S. unitholder will also be subject to a 10 % withholding tax on the amount of any distribution in excess of our cumulative net income. As we do not compute our cumulative net income for such purposes due to the complexity of the calculation and lack of clarity in how it would apply to us, we intend to treat all of our distributions as being in excess of our cumulative net income for such purposes and subject to such 10 % withholding tax. Accordingly, distributions to a non- U. S. unitholder will be subject to a combined withholding tax rate equal to the sum of the highest applicable effective tax rate and 10 %. Moreover, the transferee of an interest in a partnership that is engaged in a U. S. trade or business is generally required to withhold 10 % of the “ amount realized ” by the transferor unless the transferor certifies that it is not a foreign person. While the determination of a partner’ s “ amount realized ” generally includes any decrease of a partner’ s share of the partnership’ s liabilities, the Treasury regulations provide that the “ amount realized ” on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner’ s share of a publicly traded partnership’ s liabilities. For a transfer of interests in a publicly traded partnership that is effected through a broker, the obligation to withhold is imposed on the transferor’ s broker. Current and prospective non- U. S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units. Because we cannot match transferors and transferees of our common units and for other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns. **We have adopted certain valuation methodologies in determining a unitholder' s allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.** In determining the items of income, gain, loss and deduction allocable to our unitholders, including when we issue additional units, we must determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction. A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain recognized from the sale of our common units, have a negative impact on the value of our common units or result in audit adjustments to our unitholders’ tax returns without the benefit of additional deductions. We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the" Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize ~~the use~~ **all aspects** of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Because there are no specific rules governing the U. S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. In addition to U. S. federal income taxes, our unitholders are likely subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders are likely required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We own property and conduct business in a number of states in the United States. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is the unitholder' s responsibility to file all U. S. federal, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid. Our business is increasingly dependent on **our** information and operational technologies and services **, and those of our service providers** . Threats to information **and operational** technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. Although we utilize various procedures and controls to mitigate our exposure to such risks, cybersecurity attacks and other cyber events are evolving, unpredictable, and sometimes difficult to detect, and could lead to unauthorized access to sensitive information or render data or systems unusable. In addition, the frequency and magnitude of cyber- attacks is increasing and attackers have become more sophisticated. Cyber- attacks are similarly evolving and include **,** without limitation **,** use of malicious software, surveillance, credential stuffing, spear phishing, social engineering, use of deepfakes (i. e., highly realistic synthetic media generated by artificial intelligence), attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and **loss or** corruption of data. We may be unable to anticipate, detect or prevent future attacks, particularly as the methodologies used by attackers change frequently or are not recognized until deployed. We may also be unable to investigate or remediate incidents as attackers are increasingly using techniques and tools designed to circumvent controls, to avoid detection, and to remove or obfuscate forensic evidence. **We** ~~While we presently maintain insurance coverage to protect against cybersecurity risks, we~~ cannot ensure that ~~it~~ **our insurance coverage** will be sufficient to cover ~~any particular~~ **all the** losses **or expenses** we may experience as a result of such cyber- attacks. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent cyber- attacks or other incidents from occurring. If a cyber- attack was to occur, it could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations, misdirected wire transfers, an inability to settle transactions or maintain operations, disruptions in operations, or other adverse events. If we were to experience an attack and our security measures failed, the potential consequences to our business and the communities in which we operate could be significant and could harm our reputation and lead to financial losses ~~from remedial actions~~ , loss of business or potential liability, including regulatory enforcement, violation of privacy or securities laws and regulations, and individual or class action claims. Any cyber incident could have a material adverse effect on our business, financial condition and results of operations.