UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

☐ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2021

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File No. 001-37917

Mammoth Energy Services, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**32-0498321**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

14201 Caliber Drive, Suite 300 Oklahoma City, Oklahoma	**(405) 608-6007**	**73134**
(Address of principal executive offices)	(Registrant's telephone number, including area code)	(Zip Code)

Securities registered pursuant to Section 12(b) of The Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	TUSK	The Nasdaq Stock Market LLC NASDAQ Global Select Market

Securities registered pursuant to Section 12(g) of the Act : None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☐

The aggregate market value of common equity held by non-affiliates of the registrant as of June 30, 2021 was approximately $ 106.6 million, calculated based on the closing price of the common stock on the Nasdaq Global Select Market on that date.

As of March 2, 2022, there were 46,684,065 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATION BY REFERENCE

Portions of Mammoth Energy Services, Inc.'s Proxy Statement for the 2022 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

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GLOSSARY OF OIL AND NATURAL GAS AND ELECTRICAL INFRASTRUCTURE TERMS

The following is a glossary of certain oil and natural gas and natural sand proppant industry terms used in this Annual Report on Form 10-K (this “annual report” or “report”):

Acidizing	To pump acid into a wellbore to improve well productivity or injectivity.
Blowout	An uncontrolled flow of reservoir fluids into the wellbore, and sometimes catastrophically to the surface. A blowout may consist of salt water, oil, natural gas or a mixture of these. Blowouts can occur in all types of exploration and production operations, not just during drilling operations. If reservoir fluids flow into another formation and do not flow to the surface, the result is called an underground blowout. If the well experiencing a blowout has significant open-hole intervals, it is possible that the well will bridge over (or seal itself with rock fragments from collapsing formations) down-hole and intervention efforts will be averted.
Bottomhole assembly	The lower portion of the drillstring, consisting of (from the bottom up in a vertical well) the bit, bit sub, a mud motor (in certain cases), stabilizers, drill collar, heavy-weight drillpipe, jarring devices (“jars”) and crossovers for various threadforms. The bottomhole assembly must provide force for the bit to break the rock (weight on bit), survive a hostile mechanical environment and provide the driller with directional control of the well. Oftentimes the assembly includes a mud motor, directional drilling and measuring equipment, measurements-while-drilling tools, logging-while-drilling tools and other specialized devices.
Cementing	To prepare and pump cement into place in a wellbore.
Coiled tubing	A long, continuous length of pipe wound on a spool. The pipe is straightened prior to pushing into a wellbore and rewound to coil the pipe back onto the transport and storage spool. Depending on the pipe diameter (1 in. to 4 1/2 in.) and the spool size, coiled tubing can range from 2,000 ft. to 23,000 ft. (610 m to 6,096 m) or greater length.
Completion	A generic term used to describe the assembly of down-hole tubulars and equipment required to enable safe and efficient production from an oil or gas well. The point at which the completion process begins may depend on the type and design of the well.
Directional drilling	The intentional deviation of a wellbore from the path it would naturally take. This is accomplished through the use of whipstocks, bottomhole assembly (BHA) configurations, instruments to measure the path of the wellbore in three-dimensional space, data links to communicate measurements taken down-hole to the surface, mud motors and special BHA components and drill bits, including rotary steerable systems, and drill bits. The directional driller also exploits drilling parameters such as weight on bit and rotary speed to deflect the bit away from the axis of the existing wellbore. In some cases, such as drilling steeply dipping formations or unpredictable deviation in conventional drilling operations, directional-drilling techniques may be employed to ensure that the hole is drilled vertically. While many techniques can accomplish this, the general concept is simple: point the bit in the direction that one wants to drill. The most common way is through the use of a bend near the bit in a down-hole steerable mud motor. The bend points the bit in a direction different from the axis of the wellbore when the entire drillstring is not rotating. By pumping mud through the mud motor, the bit turns while the drillstring does not rotate, allowing the bit to drill in the direction it points. When a particular wellbore direction is achieved, that direction may be maintained by rotating the entire drillstring (including the bent section) so that the bit does not drill in a single direction off the wellbore axis, but instead sweeps around and its net direction coincides with the existing wellbore. Rotary steerable tools allow steering while rotating, usually with higher rates of penetration and ultimately smoother boreholes.
Down-hole	Pertaining to or in the wellbore (as opposed to being on the surface).
Down-hole motor	A drilling motor located in the drill string above the drilling bit powered by the flow of drilling mud. Down-hole motors are used to increase the speed and efficiency of the drill bit or can be used to steer the bit in directional drilling operations. Drilling motors have become very popular because of horizontal and directional drilling applications and the day rates for drilling rigs.
Drilling rig	The machine used to drill a wellbore.
Drillpipe or Drill pipe	Tubular steel conduit fitted with special threaded ends called tool joints. The drillpipe connects the rig surface equipment with the bottomhole assembly and the bit, both to pump drilling fluid to the bit and to be able to raise, lower and rotate the bottomhole assembly and bit.
Drillstring or Drill string	The combination of the drillpipe, the bottomhole assembly and any other tools used to make the drill bit turn at the bottom of the wellbore.
Flowback	The process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.
Horizontal drilling	A subset of the more general term “directional drilling,” used where the departure of the wellbore from vertical exceeds about 80 degrees. Note that some horizontal wells are designed such that after reaching true 90-degree horizontal, the wellbore may actually start drilling upward. In such cases, the angle past 90 degrees is continued, as in 95 degrees, rather than reporting it as deviation from vertical, which would then be 85 degrees. Because a horizontal well typically penetrates a greater length of the reservoir, it can offer significant production improvement over a vertical well.
Hydraulic fracturing	A stimulation treatment routinely performed on oil and gas wells in low permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.
Hydrocarbon	A naturally occurring organic compound comprising hydrogen and carbon. Hydrocarbons can be as simple as methane, but many are highly complex molecules, and can occur as gases, liquids or solids. Petroleum is a complex mixture of hydrocarbons. The most common hydrocarbons are natural gas, oil and coal.

Mesh size	The size of the proppant that is determined by sieving the proppant through screens with uniform openings corresponding to the desired size of the proppant. Each type of proppant comes in various sizes, categorized as mesh sizes, and the various mesh sizes are used in different applications in the oil and natural gas industry. The mesh number system is a measure of the number of equally sized openings per square inch of screen through which the proppant is sieved.
Mud motors	A positive displacement drilling motor that uses hydraulic horsepower of the drilling fluid to drive the drill bit. Mud motors are used extensively in directional drilling operations.
Natural gas liquids	Components of natural gas that are liquid at surface in field facilities or in gas processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure.
Nitrogen pumping unit	A high-pressure pump or compressor unit capable of delivering high-purity nitrogen gas for use in oil or gas wells. Two basic types of units are commonly available: a nitrogen converter unit that pumps liquid nitrogen at high pressure through a heat exchanger or converter to deliver high-pressure gas at ambient temperature, and a nitrogen generator unit that compresses and separates air to provide a supply of high pressure nitrogen gas.
Plugging	The process of permanently closing oil and gas wells no longer capable of producing in economic quantities. Plugging work can be performed with a well servicing rig along with wireline and cementing equipment; however, this service is typically provided by companies that specialize in plugging work.
Plug	A down-hole packer assembly used in a well to seal off or isolate a particular formation for testing, acidizing, cementing, etc.; also a type of plug used to seal off a well temporarily while the wellhead is removed.
Pounds per square inch	A unit of pressure. It is the pressure resulting from a one pound force applied to an area of one square inch.
Pressure pumping	Services that include the pumping of liquids under pressure.
Producing formation	An underground rock formation from which oil, natural gas or water is produced. Any porous rock will contain fluids of some sort, and all rocks at considerable distance below the Earth's surface will initially be under pressure, often related to the hydrostatic column of ground waters above the reservoir. To produce, rocks must also have permeability, or the capacity to permit fluids to flow through them.
Proppant	Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.
Resource play	Accumulation of hydrocarbons known to exist over a large area.
Shale	A fine-grained, fissile, sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers.
Tight oil	Conventional oil that is found within reservoirs with very low permeability. The oil contained within these reservoir rocks typically will not flow to the wellbore at economic rates without assistance from technologically advanced drilling and completion processes. Commonly, horizontal drilling coupled with multistage fracturing is used to access these difficult to produce reservoirs.
Tight sands	A type of unconventional tight reservoir. Tight reservoirs are those which have low permeability, often quantified as less than 0.1 millidarcies.
Tubulars	A generic term pertaining to any type of oilfield pipe, such as drill pipe, drill collars, pup joints, casing, production tubing and pipeline.
Unconventional resource/unconventional well	A term for the different manner by which resources are exploited as compared to the extraction of conventional resources. In unconventional drilling, the wellbore is generally drilled to specific objectives within narrow parameters, often across long, lateral intervals within narrow horizontal formations offering greater contact area with the producing formation. Typically, the well is then hydraulically fractured at multiple stages to optimize production.
Wellbore	The physical conduit from surface into the hydrocarbon reservoir.
Well stimulation	A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near wellbore area. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments.
Wireline	A general term used to describe well-intervention operations conducted using single-strand or multi-strand wire or cable for intervention in oil or gas wells. Although applied inconsistently, the term commonly is used in association with electric logging and cables incorporating electrical conductors.
Workover	The process of performing major maintenance or remedial treatments on an oil or gas well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense.

The following is a glossary of certain electrical infrastructure industry terms used in this report:

Distribution	The distribution of electricity from the transmission system to individual customers.
Substation	A part of an electrical transmission and distribution system that transforms voltage from high to low, or the reverse.
Transmission	The movement of electrical energy from a generating site, such as a power plant, to an electric substation.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act and the Private Securities Litigation Reform Act of 1995. In particular, the factors discussed in this report could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- the levels of capital expenditures by our customers and the impact of reduced or flat drilling and completions activity on utilization and pricing for our oilfield services;
- the volatility of oil and natural gas prices and actions by OPEC members and other oil exporting nations, or OPEC+, affecting commodity price and production levels;
- the severity and duration of the COVID-19 pandemic, the related global and national health concerns and economic repercussions and the resulting negative impact on demand for Mammoth’s services;
- operational challenges relating to the COVID-19 pandemic and efforts to mitigate the spread of the virus, including logistical challenges, remote work arrangements and protecting the health, safety and well-being of Mammoth’s employees;
- employee retention and increasingly competitive labor market;
- the performance of contracts and supply chain disruptions during the COVID-19 pandemic;
- general economic, business or industry conditions;
- conditions in the capital, financial and credit markets;
- conditions of U.S. oil and natural gas industry and the effect of U.S. energy, monetary and trade policies;
- U.S. and global economic conditions and political and economic developments, including the effects of the recent U.S. presidential and congressional elections on energy and environmental policies;
- our ability to obtain capital or financing needed for our operations on favorable terms or at all;
- our ability to continue to comply with or, if applicable, obtain a waiver of forecasted or actual non-compliance with certain financial covenants from our lenders and comply with other terms and conditions under our recently amended revolving credit facility;
- our ability to execute our business and financial strategies;
- our ability to continue to grow our infrastructure services segment, recommence certain of our suspended oilfield services or return our natural sand proppant services segment to profitability;
- any loss of one or more of our significant customers and its impact on our revenue, financial condition and results of operations;
- asset impairments;
- our ability to identify, complete and integrate acquisitions of assets or businesses;
- our ability to receive, or delays in receiving, permits and governmental approvals and/or payments, and to comply with applicable governmental laws and regulations;
- the outcome of a government investigation relating to the contracts awarded to one of our subsidiaries by the Puerto Rico Electric Power Authority and any resulting litigation;
- the outcome or settlement of our litigation matters discussed in this report, including the adverse impact of the recent settlements with Gulfport Energy Corporation, or “Gulfport”, and MasTec Renewables Puerto Rico, LLC, on our financial condition and results of operations;
- any future litigation, indemnity or other claims;
- regional supply and demand factors, delays or interruptions of production, and any governmental order, rule or regulation that may impose production limits on our customers;
- the availability of transportation, pipeline and storage facilities and any increase in related costs;
- extreme weather conditions, such as the severe winter storms in February 2021 in the Permian Basin where we provide well completion and drilling services;
- access to and restrictions on use of water;
- technology;
- civil unrest or terrorist attacks;
- cybersecurity issues as digital technologies may become more vulnerable and experience a higher rate of cyberattacks due to increased use of remote connectivity in the workplace;
- competition within the energy services industry;
- availability of equipment, materials or skilled personnel or other labor resources;

- payment of any future dividends;
- future operating results; and
- capital expenditures and other plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this annual report, are forward-looking statements. These forward-looking statements may be found in the "Business," "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations," and other sections of this annual report. In some cases, you can identify forward-looking statements by terminology such as "may," "will," "could," "should," "would," "expect," "plan," "project," "budget," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "seek," "objective," "continue," "will be," "will benefit," or "will continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors, which are difficult to predict and many of which are beyond our control. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, our management's assumptions about future events may prove to be inaccurate. Our management cautions all readers that the forward-looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the many factors including those described in Item 1A. "Risk Factors" and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this annual report. All forward-looking statements speak only as of the date of this annual report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I.

Item 1. Business

Overview

We are an integrated, growth-oriented energy services company focused on the construction and repair of the electric grid for private utilities, public investor-owned utilities and co-operative utilities through its infrastructure services businesses. We also provide products and services to enable the exploration and development of North American onshore unconventional oil and natural gas reserves. Our primary business objective is to grow our operations and create value for stockholders through organic growth opportunities and accretive acquisitions. Our suite of services includes infrastructure services, well completion services, natural sand proppant services, drilling services and other services. Our infrastructure services division provides engineering, design, construction, upgrade, maintenance and repair services to the electrical infrastructure industry. Our well completion services division provides hydraulic fracturing, sand hauling and water transfer services. Our natural sand proppant services division mines, processes and sells natural sand proppant used for hydraulic fracturing. Our drilling services division currently provides rental equipment, such as mud motors and operational tools, for both vertical and horizontal drilling. In addition to these service divisions, we also provide aviation services, equipment rentals, remote accommodations and equipment manufacturing. We believe that the services we offer play a critical role in maintaining and improving electrical infrastructure as well as in increasing the ultimate recovery and present value of production streams from unconventional resources. Our complementary suite of services provides us with the opportunity to cross-sell our services and expand our customer base and geographic positioning.

Our transformation towards an industrial based company is ongoing. We offer infrastructure engineering services focused on the transmission and distribution industry and also have equipment manufacturing operations and offer fiber optic services. Our equipment manufacturing operations provide us with the ability to repair much of our existing equipment in-house, as well as the option to manufacture certain new equipment we may need in the future. The equipment manufacturing operations have initially served the internal needs for our water transfer, equipment rental and infrastructure businesses, but we expect to expand into third party sales in the future. Our fiber optic services include the installation of both aerial and buried fiber. We are continuing to explore other opportunities to expand our business lines as we shift to a broader industrial focus.

Our facilities and service centers are strategically located in Ohio, Texas, Oklahoma, Wisconsin, West Virginia, Kentucky, California, Colorado and Alberta, Canada primarily to serve the following areas:

- The Utica Shale in Eastern Ohio;
- Southern Ohio;
- The Permian Basin in West Texas;
- The Appalachian Basin in the Northeast;
- The SCOOP and STACK in Oklahoma;
- The Arkoma Basin in Arkansas and Oklahoma;
- The Anadarko Basin in Oklahoma;
- The Marcellus Shale in West Virginia and Pennsylvania;
- Southeastern New Mexico;
- The Barnett Shale in Texas;
- The Granite Wash and Mississippi Shale in Oklahoma and Texas;
- The Cana Woodford and Woodford Shales and the Cleveland Sand in Oklahoma;
- Southern California; and
- The oil sands in Alberta, Canada.

Our operational division heads have an extensive track record in the infrastructure and oilfield service businesses with an average of over 24 years of infrastructure services experience and over 29 years of oilfield services experience. They bring valuable expertise and long-term customer relationships to our business. We provide our infrastructure services to private utilities, public investor owned utilities, or IOUs, and cooperatives, or Co-Ops, and our well completion, natural sand proppant, drilling and other services to a diversified range of both public and private independent oil and natural gas producers. For the years ended December 31, 2021 and 2020, our top five customers represented 35% and 50%, respectively, of our revenue.

Recent Developments

Impact of the Ongoing COVID-19 Pandemic and Volatility in Commodity Prices

In March and April 2020, concurrent with the spread of COVID-19 and quarantine orders in the U.S. and worldwide, oil prices dropped sharply to below zero for the first time in history due to factors including significantly reduced demand and a shortage of storage facilities. Beginning in March 2020, in response to the COVID-19 pandemic and the depressed commodity prices, many exploration and production companies, including our customers, substantially reduced their capital expenditure budgets. As a result, demand for our oilfield services declined at the end of the first quarter of 2020 and continued to decline further throughout the remainder of 2020. Exploration and production companies set their 2021 budgets based on the prevailing prices for oil and gas at the time. Although demand for oil and natural gas and commodity prices increased during the fourth quarter of 2021, these budgets for the publicly traded exploration and production companies remained relatively unchanged throughout 2021 with any excess cash flows used for debt repayment or shareholder returns rather than to increase production, as has been the case in the past. Although activity levels for exploration and production companies increased during the fourth quarter of 2021 and early 2022 due to the improvement in the U.S. and global economic activity, easing of the COVID-19 pandemic related restrictions, availability of vaccines and treatments and rising energy use and commodity prices, the emergence of the Delta COVID-19 variant in the latter part of 2021 and the subsequent surge of the highly transmissible Omicron variant continued to drive economic and pricing volatility and a cautious production outlook for 2022.

On July 18, 2021, the OPEC+ reached an agreement to phase out 5.8 million Bbl per day of oil production cuts by September 2022 as prices of crude oil reached their highest levels in more than two years. Coordinated increases in oil supply by OPEC+ began in August 2021, increasing overall oil production by 400,000 Bbl per day on a monthly basis from that point forward. Further, on January 4, 2022, OPEC+ agreed to continue to raise its output target by 400,000 Bbl per day in February 2022, which is expected to further boost oil supply in response to rising demand. In its report issued on February 10, 2022, OPEC noted its expectation that world oil demand will rise by 4.15 million Bbl per day in 2022, as the global economy continues to post a strong recovery from the COVID-19 pandemic. Although this demand outlook is expected to underpin oil prices, which have already seen a seven-year high in early 2022, we cannot predict the impact of these events on commodity prices and expect a competitive market for oilfield services for the foreseeable future.

We have taken, and continue to take, responsible steps to protect the health and safety of our employees during the COVID-19 pandemic. We are continue to monitor the adverse industry and market conditions resulting from the COVID-19 pandemic and have taken mitigating steps in an effort to preserve liquidity, reduce costs and lower capital expenditures. For additional information, see "Management’s Discussion and Analysis of Financial Condition and Results of Operations".

Our Services

Our revenues, operating (loss) income and identifiable assets are primarily attributable to four reportable segments: infrastructure services, well completion services, natural sand proppant services and drilling services.

Infrastructure Services

Our infrastructure services business provides engineering, design, construction, upgrade, maintenance and repair services to the electrical infrastructure industry. We offer a broad range of services on electric transmission and distribution, or T&D, networks and substation facilities, which include engineering, design, construction, upgrade, maintenance and repair of high voltage transmission lines, substations and lower voltage overhead and underground distribution systems. Our commercial services include the installation, maintenance and repair of commercial wiring. We also provide storm repair and restoration services in response to storms and other disasters. We provide infrastructure services primarily in the northeast, southwest, midwest and western portions of the United States.

We currently have agreements in place with private utilities, public IOUs and Co-Ops. Since we commenced operations in this line of business, a substantial portion of our infrastructure revenue has been generated from storm restoration work, primarily from the Puerto Rico Electric Power Authority, or PREPA, due to damage caused by Hurricane Maria. On October 19, 2017, Cobra Acquisitions LLC, or Cobra, and PREPA entered into an emergency master services agreement for repairs to PREPA’s electrical grid. The one-year contract, as amended, provided for payments of up to $945 million. On May 26, 2018, Cobra and PREPA entered into a second one-year, $900 million master services agreement to provide additional repair services and begin the initial phase of reconstruction of the electrical power system in Puerto Rico. Our work under each of the contracts with PREPA ended on March 31, 2019.

As of December 31, 2021, PREPA owed us approximately $227.0 million for services we performed, excluding $110.8 million of interest charged on these delinquent balances as of December 31, 2021. See Note 2. Summary of Significant Accounting Policies—Accounts Receivable and Note 19. Commitments and Contingencies to our consolidated financial statements and Item 1A. “Risk Factors—Risks Related to Our Business and the Industries We Serve” included elsewhere in this annual report for more information regarding these delinquent balances as well as other legal actions and governmental investigations related to our work for PREPA.

Our crew count declined from approximately 100 crews as of December 31, 2020 to approximately 82 crews as of December 31, 2021. Although the COVID-19 pandemic and resulting economic conditions have not had a material impact on demand or pricing for our infrastructure services, revenues for our infrastructure services have declined in 2021 as a result of certain management changes throughout the year, which resulted in crew departures, and a decline in storm restoration activities. During the third quarter of 2021, we made leadership changes in our infrastructure group. We are focused on cutting costs and enhancing accountability across the division, and we saw improvement in both areas throughout the fourth quarter of 2021.

Funding for projects in the infrastructure space remains strong with added opportunities expected in the second half of 2022 and into 2023 as a result of the Infrastructure Investment and Jobs Act, which was signed into law on November 15, 2021. We continue to pursue opportunities within this sector as we strategically structure our service offerings for growth, intending to increase our infrastructure services activity and expand both our geographic footprint and depth of projects. In late 2021, we were awarded a fiber installation contract which is expected to generate an aggregate of approximately $4.5 million in revenue over the next year. Additionally, we were awarded a multi-year electric vehicle charging station engineering contract, which could generate up to $5.0 million in revenue and will run into 2024. Both of these projects are currently in process.

We work for multiple utilities primarily across the northeastern, southwestern, midwestern and western portions of the United States. We believe that we are well-positioned to compete for new projects due to the experience of our infrastructure management team, combined with our vertically integrated service offerings. We are seeking to leverage this experience and our service offerings to grow our customer base and increase our revenues in the continental United States over the coming years.

Well Completion Services

Pressure Pumping. We provide pressure pumping services, also known as hydraulic fracturing, to exploration and production companies. Fracturing services are performed to enhance the production of oil and natural gas from formations having low permeability such that the flow of hydrocarbons is restricted. We have significant expertise in multistage fracturing of horizontal oil and natural gas producing wells in shale and other unconventional geological formations. Currently, we provide pressure pumping services in the Utica Shale of Eastern Ohio and the mid-continent region in Oklahoma.

The fracturing process consists of pumping a fracturing fluid into a well at sufficient pressure to fracture the formation. Materials known as proppants, in our case primarily sand or ceramic beads, are suspended in the fracturing fluid and are pumped into the fracture to prop it open. The fracturing fluid is designed to “break,” or loosen viscosity, and be forced out of the formation by its pressure, leaving the proppants suspended in the fractures created, thereby increasing the mobility of the hydrocarbons. As a result of the fracturing process, production rates are usually enhanced substantially, thus increasing the rate of return for the operator.

We refer to the group of fracturing units, other equipment and vehicles necessary to perform a typical fracturing job as a “fleet” and the personnel assigned to each fleet as a “crew.” We usually operate on a 24-hour-per-day basis and we typically staff three crews per fleet. All of our fracturing units and high-pressure pumps are manufactured to our specifications to enhance the performance and durability of our equipment and meet our customers’ needs.

Each hydraulic fracturing fleet includes a mobile, on-site control center that monitors pressures, rates and volumes, as applicable. From there, our field-level managers supervise the job-site by radio. Each control center is equipped with high bandwidth satellite hardware that provides continuous upload and download of job telemetry data. The data is delivered on a real-time basis to on-site job personnel, the operator and personnel at our headquarters for display in both digital and graphical form.

An important element of fracturing services is determining the proper fracturing fluid, proppants and injection program to maximize results. In virtually all of our hydraulic fracturing jobs, our customers specify the composition of the fracturing fluid to be used. The fracturing fluid may contain hazardous substances, such as hydrochloric acid and certain petrochemicals. Our customers are responsible for the disposal of the fracturing fluid that flows back out of the well as waste water. The customers remove the water from the well using a controlled flow-back process, and we are generally not involved in that process or in the disposal of the fluid.

We own and operate fleets of mobile hydraulic fracturing units and other auxiliary heavy equipment to perform fracturing services. Our hydraulic fracturing units consist primarily of a high-pressure hydraulic pump, an engine, a transmission and various hoses, valves, tanks and other supporting equipment that are typically mounted to a flat-bed trailer. As of December 31, 2021, our pressure pumping business included six high-pressure fleets consisting of an aggregate 117 high-pressure fracturing units with pump nameplate capacity of 291,750 horsepower. Currently, two of the fleets are staffed and providing services in the northeast and midcontinent regions. Over the past two years, we have converted 20 of our units to include dynamic gas blending, or DGB, capabilities to meet recent shifts in customer demand and are currently in the process of converting an additional 10 units.

Sand Hauling. Our sand hauling services provide last-mile trucking and logistics services for proppant used in completion activities in the Utica Shale and SCOOP/STACK. As of December 31, 2021, we owned a fleet of 40 trucks.

Water Transfer. Our water transfer services provide water sourcing and water transfer services primarily for completion activities in the mid-continent region. As of December 31, 2021, we owned 122 water transfer pumps and 69 miles of layflat hose.

Master Services Agreements. We contract with most of our well completion customers under master service agreements, or MSAs. Generally, our MSAs, including those relating to our hydraulic fracturing services, specify payment terms, audit rights and insurance requirements and allocate certain operational risks through indemnity and similar provision.

Natural Sand Proppant Services

In our natural sand proppant business, we mine, process and sell sand. We also buy processed sand from suppliers on the spot market and resell that sand. Natural sand proppant, also known as frac sand, is the most widely used type of proppant due to its broad applicability in unconventional oil and natural gas wells and its cost advantage relative to other proppants. Natural frac sand may be used as proppant in all but the highest pressure and temperature environments and is being employed in nearly all major U.S. unconventional oil and natural gas producing basins, including those in which we operate.

At our Barron County and Jackson County, Wisconsin plants, we mine and process sand into premium monocrystalline sand, a specialized mineral that is used as frac sand. We can also purchase raw or washed sand and process it at our indoor sand processing plant located in Pierce County, Wisconsin; however, this facility has been temporarily idled since September 2018 due to market conditions. We sell sand to our customers for use in their hydraulic fracturing operations to enhance recovery rates from unconventional wells. Our sand processing plants produce a range of frac sand sizes for use in all major North American shale basins, including a majority of the standard proppant sizes as defined by the ISO/API 13503-2 specifications. These grain sizes can be customized to meet the demands of our customers with respect to a specific well. Our supply of Jordan substrate exhibits the physical properties necessary to withstand the completion and production environments of the wells in these shale basins. Our indoor processing plant in Pierce County, Wisconsin is designed for year-round continuous wet and dry plant operation. Our multi-environment processing plants in Barron County and Jackson County, Wisconsin have indoor dry plants designed to operate year-round and outdoor wet plants that generally operate eight months per year.

We also provide logistics solutions to facilitate delivery of our frac sand products to our customers. Our frac sand products are primarily shipped by rail to our customers in the Utica Shale, SCOOP/STACK, DJ Basin, Permian Basin and the Montney Shale in British Columbia and Alberta, Canada. Our logistics capabilities are important to our customers, who focus on both the reliability and flexibility of product delivery. Because our customers generally find it impractical to store frac sand in large quantities near their well completion sites, they typically prefer product to be delivered where and as needed, which requires predictable and efficient loading and shipping capabilities. We contract with third party providers to transport our frac sand products to railroad facilities for delivery to our customers. We currently lease or have access to origin transloading facilities on the Canadian National Railway Company (CN), Union Pacific (UP), Burlington Northern Santa Fe (BNSF) and the Canadian Pacific (CP) rail systems and use an in-house railcar fleet that we lease from various third parties to deliver our frac sand products to our customers. Origin transloading facilities on multiple railways allow us to provide predictable and efficient loading and shipping of our frac sand products. We also utilize a destination transloading facility in Yorkville, Ohio, to serve the Utica Shale, and utilize destination transloading facilities located in other North American resource plays, including the Montney Shale, to meet our customers’ delivery needs.

Drilling Services

During certain of the periods discussed in this report, we offered contract land and directional drilling services as well as rig moving services. Due to market conditions, we temporarily shut-down our contract land drilling operations beginning in December 2019. We continue to monitor market conditions to determine if and when we will recommence these services.

Contract Drilling. As part of our contract drilling services, we provided both vertical and horizontal drilling services to customers in the Permian Basin of West Texas. As of December 31, 2021, we owned 12 land drilling rigs, ranging from 800 to 1,600 horsepower, eight of which are specifically designed for drilling horizontal and directional wells.

Our drilling rigs have rated maximum depth capabilities ranging from 12,500 feet to 20,000 feet. Of these drilling rigs, seven are electric rigs and five are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the power from its generators (which in the case of mechanical rigs, power the rig directly) into electricity to power the rig. Depth and complexity of the well and drill site conditions are the principal factors in determining the specifications of the rig selected for a particular job. Power requirements for drilling jobs may vary considerably, but most of our mechanical drilling rigs employ six engines to generate between 800 and 1,200 horsepower, depending on well depth and rig design. Most drilling rigs capable of drilling in deep formations drill to measured depths greater than 10,000 to 18,000 feet. Generally, land rigs operate with four crews of five people and two tool pushers, or rig managers, rotating on a weekly or bi-weekly schedule.

We believe that our drilling rigs and other related equipment are in good operating condition. Our employees perform periodic maintenance and minor repair work on our drilling rigs.

Prior to our temporary shutdown of these services in December 2019, we obtained our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with customers. We typically entered into drilling contracts that provided for compensation on a daywork basis. Occasionally, we entered into drilling contracts that provided for compensation on a footage basis; however, a majority of such footage drilling contracts also provided for daywork rates for work outside core drilling activities contemplated by such footage contracts and under certain other circumstances. We have not historically entered into turnkey contracts; however, we may decide to enter into such contracts in the future. It is also possible that we may acquire such contracts in connection with future acquisitions of drilling assets. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, the anticipated duration of the work to be performed and market conditions.

Directional Drilling. Our directional drilling services provide for the efficient drilling and production of oil and natural gas from unconventional resource plays. Our directional drilling equipment includes mud motors used to propel drill bits and kits for measurement-while-drilling, or MWD, and electromagnetic, or EM, technology. MWD kits are down-hole tools that provide real-time measurements of the location and orientation of the bottom-hole assembly, which is necessary to adjust the drilling process and guide the wellbore to a specific target. This technology, coupled with our complementary services, allows our customers to drill wellbores to specific objectives within narrow location parameters within target horizons. The evolution of unconventional resource reserve recovery has increased the need for the precise placement of a wellbore. Wellbores often travel across long-lateral intervals within narrow formations as thin as ten feet. Our personnel are involved in all aspects of a well from the initial planning of a customer’s drilling program to the management and execution of the horizontal or directional drilling operation.

As of December 31, 2021, we owned five MWD kits and one EM kit used in vertical, horizontal and directional drilling applications, 89 mud motors, 16 air motors and an inventory of related parts and equipment. Currently, we perform our directional drilling services in the Utica Shale, Anadarko Basin, Arkoma Basin, Powder River Basin and Permian Basin.

Rig Moving. We provided rig moving services in the Permian Basin. Due to market conditions, we temporarily shut-down our rig moving operations beginning in April 2020. As of December 31, 2021, we owned 16 trucks specifically tailored to move rigs and seven cranes to assist us in moving rigs.

Other Services

We also offer a variety of other services including aviation services, equipment rental services, remote accommodation services and equipment manufacturing services. Additionally, during certain of the periods discussed in this report, we offered coil tubing services, pressure control services, flowback services, crude oil hauling services, cementing services and acidizing services.

Aviation Services. Our aviation services include leasing helicopters to customers for use primarily in the electrical utility industry. Additionally, we provide helicopter training and response services. As of December 31, 2021, we owned four helicopters.

Equipment Rentals. Our equipment rental services provide a wide range of oilfield related equipment used in drilling, flowback and hydraulic fracturing services. Our equipment rentals consist of cranes, light plants, generators and other oilfield related equipment. We provide equipment rental in the Utica Shale, Eagle Ford Shale and mid-continent region. Additionally, we provide water transfer services in the northeast region. As of December 31, 2021, we owned 18 water transfer pumps, 30 miles of layflat hose and ten miles of poly pipe for use in our water transfer operations.

Remote Accommodations. Our remote accommodations business provides housing, kitchen and dining, and recreational service facilities for oilfield workers located in remote areas away from readily available lodging. We provide a turnkey solution for our customers' accommodation needs. These modular camps, when assembled together, form large dormitories, with kitchen/dining facilities and recreation areas. These camps are operated as "all inclusive," where meals are prepared and provided for the guests. The primary revenue source for these camps is lodging fees. As of December 31, 2021, we had a capacity of 878 rooms, 612 of which are at Sand Tiger Lodge, our camp in northern Alberta, Canada, and 266 of which are available to be leased as rental equipment to a third party. On average, 90 rooms were utilized per night during the year ended December 31, 2021.

Equipment Manufacturing. During 2019, we commenced equipment manufacturing operations at our facility located in Oklahoma. These operations have initially served our internal needs for our water transfer, equipment rental and infrastructure businesses, but we intend to expand into third party sales in the future.

We also offered coil tubing services, pressure control services, flowback services, crude oil hauling services, cementing services and acidizing services during certain of the periods discussed in this report. Due to market conditions, we temporarily shut down our flowback, cementing and acidizing operations beginning in July 2019, our coil tubing, pressure control and full service transportation operations beginning in July 2020 and our crude oil hauling operations beginning in July 2021. We continue to monitor market conditions to determine if and when we will recommence these services.

Flowback. Our flowback services consisted of production testing, solids control, hydrostatic testing and torque services. Flowback involves the process of allowing fluids to flow from the well following a treatment, either in preparation for an impending phase of treatment or to return the well to production. Our flowback equipment consists of manifolds, accumulators, valves, flare stacks and other associated equipment that combine to form up to a total of five well-testing spreads. We provided flowback services in the Appalachian Basin, the Eagle Ford Shale, the Haynesville Shale and mid-continent markets. As of December 31, 2021, we owned five production testing packages, 20 solids control packages, four hydrostatic testing packages and seven torque service packages.

Cementing and Acidizing. We provided cementing and acidizing services in the Permian Basin. Cementing services involve preparing and pumping cement into place in a wellbore to support and protect well casings and help achieve zonal isolation. Acidizing services involve pumping acid into a wellbore to improve productivity or injectivity. As of December 31, 2021, we owned two twin cementers and associated equipment and four acidizing pumps.

Coil Tubing. We provided coil tubing services in Eagle Ford Shale and Permian Basin. Coiled tubing services involve injecting coiled tubing into wells to perform various well-servicing and workover operations. Coiled tubing is a flexible steel pipe with a diameter of typically less than three inches and manufactured in continuous lengths of thousands of feet. It is wound or coiled on a truck-mounted reel for onshore applications. Due to its small diameter in certain iterations, coiled tubing can be inserted into existing production tubing and used to perform a variety of services to enhance the flow of oil or natural gas without using a larger, more costly workover rig. The principal advantages of using coiled tubing in a workover include the ability to (i) continue production from the well without interruption, thus reducing the risk of formation damage, (ii) move continuous coiled tubing in and out of a well significantly faster than conventional pipe in the case of a workover rig, which must be jointed and unjointed, (iii) direct fluids into a wellbore with more precision, allowing for improved stimulation fluid placement, (iv) provide a source of energy to power a downhole mud motor or manipulate down-hole tools and (v) enhance access to remote fields due to the smaller size and mobility of a coiled tubing unit. As of December 31, 2021, we had one coiled tubing unit capable of running 25,000 feet of two and five eighths inch coil rated at 15,000 pounds per square inch, or psi, two coiled tubing units capable of running 23,500 feet of two and three eighths inch coil rated at 15,000 psi, one coiled tubing unit capable of running 24,500 feet of two inch coil rated at 15,000 psi, two coiled tubing units capable of running over 22,000 feet of two inch coil rated at 10,000 psi and one coiled tubing unit capable of running 20,500 feet of two and three eighths inch coil rated at 15,000 psi in service.

Pressure Control. Our pressure control services consisted of nitrogen and fluid pumping services. Our pressure control services equipment is designed to support activities in unconventional resource plays with the ability to operate under high pressures without having to delay or cease production during completion operations. Ceasing or suppressing production during the completion phase of an unconventional well could result in formation damage impacting the overall recovery of reserves. Our pressure control services help operators minimize the risk of such damage during completion activities. As of December 31, 2021, we had a total of four nitrogen pumping units and seven fluid pumping units. We have provided pressure control services in the Eagle Ford Shale in South Texas and the Permian Basin in West Texas.

- ***Nitrogen Services.*** Nitrogen services involve the use of nitrogen, an inert gas, in various pressure pumping operations. When provided as a stand-alone service, nitrogen is used in displacing fluids in various oilfield applications. As of December 31, 2021, we had a total of four nitrogen pumping units capable of pumping at a rate of up to 3,000 standard cubic feet per minute with pressures up to 10,000 psi. Pumping at these rates and pressures is typically required for the unconventional oil and natural gas resource plays we serve.
- ***Fluid Pumping Services.*** Fluid pumping services consist of maintaining well pressure, pumping down wireline tools, assisting coiled tubing units and the removal of fluids and solids from the wellbore for clean-out operations. As of December 31, 2021, we had seven fluid pumping units. Five of these units are coiled tubing double pump units capable of output of up to eight barrels per minute, and are rated for pressures up to 15,000 psi. Two of these units are quintuplex pump units capable of output of up to 15 barrels per minute, and are rated for pressures up to 15,000 psi.

Full Service Transportation. During 2019, we expanded our trucking operations to include brokering and hauling of general freight throughout the United States. As of December 31, 2021, we had a fleet of six trucks.

Crude Oil Hauling. We provide crude transportation services in the Permian Basin and mid-continent region. As of December 31, 2021, we had a fleet of 14 crude oil hauling trucks.

Our Industries

Electric Infrastructure Industry

The electrical infrastructure industry involves the construction and maintenance of the electrical power grid, including, but not limited to, power generation, high voltage transmission lines, substations and low voltage distribution lines, all of which connect power generation facilities to end users. The industry also provides storm repair and restoration services in response to storms and other disasters. The industry is highly fragmented with more than 3,300 separate electric utility companies identified in the United States in 2019, spread across the following subgroups: IOUs, private utilities and Co-Ops.

Demand for our services is driven by the repair and construction of transmission lines, substations and distribution networks and is determined by the level of expenditures of utility companies. While expansion of the electrical grid is occurring, the majority of capital expenditures spent in recent years has surrounded the repair and maintenance of existing networks. Another factor that significantly influences the level of spending in the industry are natural disasters, which impact the electrical grid. These natural disasters include, but are not limited to, thunderstorms, ice storms, snow storms, tornadoes, hurricanes, earthquakes, wildfires and lightning strikes.

Certain barriers to entry exist in the markets in which we operate, including adequate financial resources, technical expertise, high safety ratings and a proven track record of operational success. We compete based upon our industry experience, technical expertise, financial and operational resources, geographic presence, industry reputation, safety record and customer service. While we believe our customers consider a number of factors when selecting a service provider, they generally award most of their work through a bid process. Consequently, price is often a principal factor in determining which service provider is selected.

We believe that the age of the existing infrastructure across the United States and the spending trends in North America will benefit our operations and our ability to achieve our business objectives. Funding for projects in the infrastructure space remains strong with added opportunities expected from the Infrastructure Investment and Jobs Act, which was signed into law on November 15, 2021.

Oil and Natural Gas Industry

The oil and natural gas industry has traditionally been volatile and is influenced by a combination of long-term, short-term and cyclical trends, including the domestic and international supply and demand for oil and natural gas, current and expected future prices for oil and natural gas and the perceived stability and sustainability of those prices, production depletion rates and the resultant levels of cash flows generated and allocated by exploration and production companies to their drilling, completion and related services and products budget. The oil and natural gas industry is also impacted by general domestic and international economic conditions, political instability in oil producing countries, government regulations (both in the United States and elsewhere), levels of customer demand, the availability of pipeline capacity and other conditions and factors, including global and national health concerns, that are beyond our control. See "Recent Developments—Impact of the Ongoing COVID-19 Pandemic and Volatility in Commodity Prices" above.

Demand for most of our oil and natural gas products and services depends substantially on the level of expenditures by companies in the oil and natural gas industry. The levels of capital expenditures of our customers are predominantly driven by the prices of oil and natural gas. In March and April 2020, concurrent with the spread of COVID-19 and quarantine orders in the U.S. and worldwide, oil prices dropped sharply to below zero for the first time in history due to factors including significantly reduced demand and a shortage of storage facilities. Beginning in March 2020, in response to the COVID-19 pandemic and the depressed commodity prices, many exploration and production companies, including our customers, substantially reduced their capital expenditure budgets. As a result, demand for our oilfield services declined at the end of the first quarter of 2020 and continued to decline further throughout the remainder of 2020. Exploration and production companies set their 2021 budgets based on the prevailing prices for oil and gas at the time. Although demand for oil and natural gas and commodity prices increased during the fourth quarter of 2021, these budgets for the publicly traded exploration and production companies remained relatively unchanged throughout 2021 with any excess cash flows used for debt repayment or shareholder returns rather than to increase production, as has been the case in the past. Activity levels for exploration and production companies, however, increased during the fourth quarter of 2021 and early 2022 due to the recent improvement in the U.S. and global economic activity, easing of the COVID-19 pandemic related restrictions, availability of vaccines and treatments and rising energy use and commodity prices, the emergence of the Delta COVID-19 variant in the latter part of 2021 and the subsequent surge of the highly transmissible Omicron variant continued to contribute to the economic and pricing volatility and a cautious production outlook for 2022.

On July 18, 2021, the OPEC+ reached an agreement to phase out 5.8 million barrels per day of oil production cuts by September 2022 as prices of crude oil reached their highest levels in more than two years. Coordinated increases in oil supply by OPEC+ began in August 2021, increasing overall oil production by 400,000 barrels per day on a monthly basis from that point forward. Further, on January 4, 2022, OPEC+ agreed to continue to raise its output target by 400,000 Bbl per day in February 2022, which is expected to further boost oil supply in response to rising demand. In its report issued on February 10, 2022, OPEC noted its expectation that world oil demand will rise by 4.15 million Bbl per day in 2022, as the global economy continues to post a strong recovery from the COVID-19 pandemic. Although this demand outlook is expected to underpin oil prices, which have already seen a seven-year high in early 2022, we cannot predict the impact of these events on commodity prices and expect a competitive market for oilfield services for the foreseeable future.

In response to market conditions, we temporarily shut down our cementing and acidizing operations and flowback operations beginning in July 2019, our contract drilling operations beginning in December 2019, our rig hauling operations beginning in April 2020, our coil tubing, pressure control and full service transportation operations beginning in July 2020 and our crude oil hauling operations beginning in July 2021. We continue to monitor the market to determine if and when we can recommence these services.

Natural Sand Proppant Industry

In 2018 and 2019, several new and existing suppliers completed planned capacity additions of frac sand supply, particularly in the Permian Basin. The industry expansion, coupled with increased capital discipline, budget exhaustion and the impact on oil demand from the COVID-19 pandemic, caused the frac sand market to become oversupplied, particularly in finer grades. With the frac sand market oversupplied, pricing for all grades has fallen significantly from the peaks experienced throughout 2018 and during the first half of 2019. This oversupply resulted in several industry participants idling and closing high cost mines in an attempt to restore the supply and demand balance. Despite such attempts, demand for our sand declined significantly in the second half of 2019 and throughout 2020 as a result of the factors discussed above. As well drilling and completions began ramping back up in 2021, overall demand for frac sand increased from the 2020 levels, reaching approximately 93 million tons in 2021, although the Northern White silica sand that we produce continued to face strong competition with Texas frac sand. We have seen a recent uptick in activity in Canada, which we currently expect to continue throughout 2022. However, rail constraints persist, causing shipping delays and adversely impacting the recovery of the

Northern White frac sand market. We cannot predict if and when demand and pricing will recover sufficiently to return our natural sand proppant services segment to profitability.

Our proppant sand reserves consist of Northern White silica sand, giving us access to a range of high-quality sand grades meeting or exceeding all API specifications, including a mix between concentrations of coarse grades (20/40 and 30/50 mesh size) and finer grades (40/70 and 100 mesh size). Our sample boring data and our historical production data have indicated that our reserves contain deposits of approximately 60% 40 mesh size or finer substrate. The coarseness and conductivity of Northern White frac sand significantly enhances recovery of oil and liquids-rich gas by allowing hydrocarbons to flow more freely than is sometimes possible with native sand. The low acid-solubility increases the integrity of Northern White frac sand relative to other proppants with higher acid-solubility, especially in shales where hydrogen sulfide and other acidic chemicals are co-mingled with the targeted hydrocarbons. In addition, its crush resistant properties enable Northern White frac sand to be used in deeper drilling applications than the frac sand produced from many native mineral deposits.

We believe that the coarseness, conductivity, sphericity, acid-solubility, and crush-resistant properties of our Northern White sand reserves and our facilities' connectivity to rail and other transportation infrastructure afford us a cost advantage over many of our competitors and make us one of a select group of sand producers capable of delivering high volumes of frac sand that is optimal for oil and natural gas production to all major unconventional resource basins currently producing throughout North America.

Our Strengths

Our primary business objective is to grow our operations and create value for our stockholders through organic growth opportunities and accretive acquisitions. We believe that the following strengths position us well to capitalize on activity in unconventional resource plays and achieve our primary business objective:

- *Strategic geographic positioning.* We currently operate infrastructure facilities and service centers to support our infrastructure operations in the northeast, southwest, midwest and western portions of the United States. We currently operate facilities and service centers to support our oilfield service operations in major unconventional resource plays in the United States, including the Utica Shale in Eastern Ohio, the Permian Basin in West Texas, the SCOOP/STACK in Oklahoma, the Marcellus Shale in West Virginia, the Granite Wash in Oklahoma and Texas, the Cana Woodford Shale in Oklahoma and the oil sands in Alberta, Canada. We believe our geographic positioning within active oil and natural gas liquids resource plays will benefit us strategically as activity increases in these unconventional resource plays.

- *Experienced management and operating team.* Our operational division heads have an extensive track record in the oilfield and infrastructure service businesses with an average of over 24 years of infrastructure services experience and over 29 years of oilfield services experience. In addition, our field managers have expertise in the areas in which they operate and understand the challenges that our customers face. We believe their knowledge of our industries and business lines enhances our ability to provide innovative, client-focused and basin-specific customer service, which we also believe strengthens our relationships with our customers.

- *Young fleet of equipment.* Our infrastructure service fleet is predominantly comprised of equipment designed to construct and repair electric transmission and distribution lines and our oilfield service fleet is predominantly comprised of equipment designed to optimize recovery from unconventional wells. Three of our pressure pumping fleets with total combined horsepower of 132,500 were built in 2017. We believe that our fleet of quality equipment will allow us to provide a high level of service to our customers. In addition, over the past two years we have converted 20 of our pressure pumping units to include DGB capabilities to meet recent shifts in customer demand and expect to convert 10 more units during 2022.

Our Business Strategy

We intend to achieve our primary business objective in connection with our infrastructure services by the successful execution of our business plan to strategically deploy equipment and personnel to provide infrastructure services across the United States. We believe our infrastructure services optimize our customers' ability to maintain, improve and expand their infrastructure and that our oil and natural gas services optimize our customers' ultimate resources recovery and present value of hydrocarbon reserves. In the case of our oilfield services, we intend to achieve our primary business objective by the successful execution of our business plan to strategically deploy our equipment and personnel to provide well completion services, natural sand proppant services and other energy services in unconventional resource plays, including the Utica Shale in Ohio, the SCOOP/STACK in Oklahoma and the Permian Basin in West Texas. We seek to create cost efficiencies for our customers by providing a suite of complementary services designed to address a wide range of our customers' needs. Specifically, we strive to create value for our stockholders through the following strategies:

- *Leverage our broad range of services for cross-selling opportunities.* We offer a complementary suite of services and products. Our infrastructure services division provides engineering, design, construction, upgrade, maintenance and repair services to the electrical infrastructure industry. Our well completion services division provide hydraulic fracturing services for unconventional wells as well as sand hauling services and water transfer services. Our natural sand proppant services division mines, processes and sells natural sand proppant for hydraulic fracturing. Additionally, we provide directional drilling services, equipment rentals, remote accommodations and equipment manufacturing. We intend to leverage our existing customer relationships and operational track record to cross sell our services and increase our exposure and product offerings to our existing customers, broaden our customer base and expand opportunistically to other geographic regions in which our customers have operations, as well as to create operational efficiencies for our customers.

- *Expand our energy infrastructure business.* On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act into law. This is expected to bring new opportunities in the infrastructure industry, including new fiber-related projects. We consistently monitor market conditions and intend to expand the capacity and scope of our energy infrastructure services as demand warrants in geographic areas in which we currently operate, as well as in new geographic areas.

- *Maintain a conservative balance sheet.* We seek to maintain a conservative balance sheet, which allows us to better react to changes in commodity prices and related demand for our services, as well as overall market conditions.

- *Expand our services to meet expanding customer demand.* The scope of services for horizontal wells is greater than that for conventional wells. Industry analysts have reported that the average horsepower required for current completion designs, amount of sand per lateral foot, length of lateral and number of fracture stages has continued to increase since 2008. We consistently monitor market conditions and intend to expand the capacity and scope of our business lines if, and when, demand warrants in resource plays in which we currently operate, as well as in new resource plays. If we perceive unmet demand in our principal geographic locations for different service lines, we will seek to expand our current service offerings to meet that demand.

- *Leverage our experienced operational management team expertise.* We seek to manage the services we provide as closely as possible to the needs of our customer base. Our operational division heads have long-term relationships with our largest customers. We intend to leverage these relationships and our operational management team's expertise to deliver innovative, client focused and services to our customers.

- *Expand through selected, accretive acquisitions.* To complement our organic growth, we intend to pursue selected, accretive acquisitions of businesses and assets, primarily related to our infrastructure services, completion and production services and industrial based companies, that can meet our targeted returns on invested capital and enhance our portfolio of products and services, market positioning and/or geographic presence. We believe this approach will help facilitate the strategic expansion of our customer base, geographic presence and service offerings. We also believe that our industry contacts and those of Wexford Capital LP, or Wexford, our largest stockholder, may help us identify acquisition opportunities. We may use our common stock as consideration for accretive acquisitions.

- *Capitalize on activity in the unconventional resource plays.* Our oil and natural gas service equipment is designed to provide a broad range of services for unconventional wells, and our operations are strategically located in major unconventional resource plays. During 2021, oil prices fluctuated between a low of $47.62 on January 4, 2021 and a high of $84.65 on October 26, 2021, and averaged $68.17 per barrel for the year. This extreme price volatility reduced the demand for our oilfield services. We cannot predict if or when commodity prices will stabilize and at what levels, but we will seek to capitalize on any increase in activity in our existing markets and diversify our operations across additional unconventional resource basins as opportunities arise.

Marketing and Customers

Our customers consist primarily of private utilities, IOUs, Co-Ops, independent oil and natural gas producers and land-based drilling contractors in North America. For the years ended December 31, 2021, 2020 and 2019, we had approximately 480, 530 and 590 customers, respectively, including American Electric Power Company, Gulfport, Liberty Oilfield Services Inc., Hilcorp Energy and Arsenal Resources. Our top five customers accounted for approximately 35%, 50% and 53%, respectively, of our revenue for the years ended December 31, 2021, 2020 and 2019. During the years ended December 31, 2021 and 2020, Gulfport accounted for 7% and 16%, respectively, of our revenue. For the year ended December 31, 2019, Gulfport and PREPA accounted for 20% and 15%, respectively, of our revenue. Our services for PREPA and Gulfport have ended. Although we believe we have a broad customer base and wide geographic coverage of operations, it is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. If a major customer decides not to continue to use our services and is not replaced by new or existing customers, our revenue would decline and our operating results and financial condition would be harmed.

Operating Risks and Insurance

Our operations are subject to hazards inherent in the energy services industry, such as accidents, blowouts, explosions, fires and spills and releases that can cause:

- personal injury or loss of life;
- damage or destruction of property, equipment, natural resources and the environment; and
- suspension of operations.

In addition, claims for loss of oil and natural gas production and damage to formations can occur in the oilfield services industry. If a serious accident were to occur at a location where our equipment and services are being used, it could result in us being named as a defendant in lawsuits asserting large claims.

Because our business involves the transportation of heavy equipment and materials, we may also experience traffic accidents which may result in spills, property damage and personal injury.

Despite our efforts to maintain safety standards, from time to time we have suffered accidents in the past and anticipate that we could experience accidents in the future. In addition to the property damage, personal injury and other losses from these accidents, the frequency and severity of these incidents affect our operating costs and insurability and our relationships with customers, employees, regulatory agencies and other parties. Any significant increase in the frequency or severity of these incidents, or the general level of compensation awards, could adversely affect the cost of, or our ability to obtain, workers’ compensation and other forms of insurance, and could have other material adverse effects on our financial condition and results of operations.

We maintain commercial general liability, workers’ compensation, business auto, commercial property, motor truck cargo, umbrella liability, in certain instances, excess liability, and directors and officers insurance policies providing coverages of risks and amounts that we believe to be customary in our industry. With respect to our hydraulic fracturing operations, coverage would be available under our policy for any surface or subsurface environmental clean-up and liability to third parties arising from any surface or subsurface contamination. We also have certain specific coverages for some of our businesses, including our remote accommodation services, pressure pumping services, contract and directional drilling services and infrastructure engineering services.

Although we maintain insurance coverage of types and amounts that we believe to be customary in the industry, we are not fully insured against all risks, either because insurance is not available or because of the high premium costs relative to perceived risk. Further, insurance rates have in the past been subject to wide fluctuation and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on us. See Item 1A. “Risk Factors” for a description of certain risks associated with our insurance policies.

Safety and Remediation Program

In the energy services industry, an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced and skilled workforce. Many of our larger customers place an emphasis not only on pricing, but also on safety records and quality management systems of contractors. We have committed resources toward employee safety and quality management training programs. Our field employees are required to complete both technical and safety training programs. Further, as part of our safety program and remediation procedures, we check treating iron for any defects on a periodic basis to avoid iron failure during hydraulic fracturing operations, marking such treating iron to reflect the most recent testing date. We also regularly monitor pressure levels in the treating iron used for fracturing and the surface casing to verify that the pressure and flow rates are consistent with the job specific model in an effort to avoid failure. As part of our safety procedures, we also have the capability to shut down our pressure pumping and fracturing operations both at the pumps and in our data van. In addition, we maintain spill kits on location for containment of pollutants that may be spilled in the process of providing our hydraulic fracturing services. The spill kits are generally comprised of pads and booms for absorption and containment of spills, as well as soda ash for neutralizing acid. Fire extinguishers are also in place on job sites at each pump.

Historically, we have used third-party contractors to provide remediation and spill response services when necessary to address spills that were beyond our containment capabilities. None of these prior spills were significant, and we have not experienced any incidents, citations or legal proceeding relating to our hydraulic fracturing or crude hauling services for environmental concerns. To the extent our hydraulic fracturing or other energy services operations result in a future spill, leak or other environmental impact that is beyond our ability to contain, we intend to engage the services of such remediation company or an alternative company to assist us with clean-up and remediation.

Competition

The markets in which we operate are highly competitive. To be successful, a company must provide services and products that meet the specific needs of oil and natural gas exploration and production companies, drilling services contractors, private utilities, IOUs and Co-Ops at competitive prices.

We provide our services and products across the United States and in Alberta, Canada and we compete against different companies in each geographic area and service and product line we offer. Our competition includes many large and small energy service companies, including the largest integrated oilfield services companies and energy infrastructure companies. Our major competitors for our infrastructure services business include MYR Group, Inc., Quanta Services, Inc., MasTec, Inc. and EMCOR Group, Inc. Our major competitors in well completion services include Halliburton Company, U.S. Well Services, LLC, NexTier Oilfield Solutions, Inc., RPC Incorporated, Liberty Oilfield Services, Inc. and FTS International, Inc. Our major competitors in our natural sand proppant services business are Badger Mining Corporation, Covia Holdings Corporation, Hi-Crush Partners LP, Capital Sand Proppants LLC and U.S. Silica Holdings Inc.

We believe that the principal competitive factors in the market areas that we serve are quality of service and products, reputation for safety, technical proficiency, availability and price. While we must be competitive in our pricing, we believe our customers select our services and products based on the local leadership and expertise that our field management and operating personnel use to deliver quality services and products.

Regulation

We operate under the jurisdiction of a number of regulatory bodies that regulate worker safety standards, permitting and inspection requirements applicable to construction projects, building and electrical codes regulations, government project regulations, the handling of hazardous materials, the transportation of explosives, the protection of human health and the environment and driving standards of operation. Regulations concerning equipment certification create an ongoing need for regular maintenance which is incorporated into our daily operating procedures. The oil and natural gas and infrastructure industries are subject to environmental and other regulation pursuant to local, state and federal legislation.

Regulation of Infrastructure Services

In our infrastructure business, our operations are subject to various federal, state and local laws and regulations including:

- licensing, permitting and inspection requirements applicable to contractors, electricians and engineers;
- regulations governing environmental and conservation matters;

- regulations relating to worker safety;
- permitting and inspection requirements applicable to construction projects;
- wage and hour regulations;
- building and electrical codes; and
- special bidding, procurement and other requirements on government projects.

We believe that we have all the licenses required to conduct our energy infrastructure services and that we are in substantial compliance with applicable regulatory requirements. Our failure to comply with applicable regulations could result in substantial fines or revocation of our operating licenses, as well as give rise to termination or cancellation rights under our contracts or disqualify us from future bidding opportunities.

Transportation Matters

In connection with the transportation and relocation of our equipment and shipment of frac sand, crude oil and general cargo, we operate trucks and other heavy equipment. As such, we operate as a motor carrier in providing certain of our services and therefore are subject to regulation by the United States Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations, driver licensing and insurance requirements, financial reporting and review of certain mergers, consolidations and acquisitions, and transportation of hazardous materials (HAZMAT). Our trucking operations are subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive or work in any specific period, onboard black box recorder device requirements or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the Federal Motor Carrier Safety Administration, or FMCSA, a unit within the United States Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Matters such as the weight and dimensions of equipment are also subject to federal and state regulations. From time to time, various legislative proposals are introduced, including proposals to increase federal, state or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Certain motor vehicle operators require registration with the Department of Transportation. This registration requires an acceptable operating record. The Department of Transportation periodically conducts compliance reviews and may revoke registration privileges based on certain safety performance criteria which could result in a suspension of operations. The rating scale consists of “satisfactory,” “conditional” and “unsatisfactory” ratings. As of December 31, 2021, all of our trucking operations have “satisfactory” ratings with the Department of Transportation. We have undertaken comprehensive efforts that we believe are adequate to comply with the regulations. Further information regarding our safety performance is available at the FMCSA website at www.fmcsa.dot.gov.

In December 2010, the FMCSA launched a program called Compliance, Safety, Accountability, or CSA, in an effort to improve commercial truck and bus safety. A component of CSA is the Safety Measurement System, or SMS, which analyzes all safety violations recorded by federal and state law enforcement personnel to determine a carrier’s safety performance. The SMS is intended to allow FMCSA to identify carriers with safety issues and intervene to address those problems. However, the agency has announced a future intention to revise its safety rating system by making greater use of SMS data in lieu of on-site compliance audits of carriers. At this time, we cannot predict the effect such a revision may have on our safety rating.

Environmental Matters and Regulation

Our operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before commencing operations, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with our operations, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or related to our owned or operated facilities. Liability under such laws and regulations is strict (i.e., no showing of “fault” is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry and infrastructure industry in general. We have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. We handle, transport, store and dispose of wastes that are subject to the federal Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, which affect our activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although certain petroleum production wastes are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. Moreover, the EPA or state or local governments may adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Several environmental organizations have also petitioned the EPA to modify existing regulations to recategorize certain oil and natural gas exploration, development and production wastes as “hazardous.” Also, in December 2015, the EPA agreed in a consent decree to review its regulation of oil and gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, which we refer to as CERCLA, or the “Superfund” law, and analogous state laws, generally imposes liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” are subject to strict liability, that, in some circumstances, may be joint and several for the costs of removing or remediating previously disposed substances (including substances disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

NORM. In the course of our operations, some of our equipment may be exposed to naturally occurring radioactive materials associated with oil and gas deposits and, accordingly may result in the generation of wastes and other materials containing naturally occurring radioactive materials, or NORM. NORM exhibiting levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping and work area affected by NORM may be subject to remediation or restoration requirements. Because certain of the properties presently or previously owned, operated or occupied by us may have been used for oil and gas production operations, it is possible that we may incur costs or liabilities associated with NORM.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers, which we refer to as the

Corps. The scope of waters regulated under the CWA has fluctuated in recent years. On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 rules, and then, on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rules, and significantly reducing the waters subject to federal regulation under the Clean Water Act. On August 30, 2021, a federal court struck down the replacement rule and, on December 7, 2021, the EPA and the Corps published a proposed rule that would put back into place the pre-2015 definition of "waters of the United States," updated to reflect Supreme Court decisions, while the agencies continue to consult with stakeholders on future regulatory actions. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants, which regulations are discussed in more detail below under the caption "—Regulation of Hydraulic Fracturing." Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Also, spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Noncompliance with these requirements may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, our sand proppant services operations are subject to air permits issued by the Wisconsin Department of Natural Resources regulating our emission of fugitive dust and other constituents. These and other laws and regulations may increase the costs of compliance for some facilities where we operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas and infrastructure projects.

Climate Change. In recent years, federal, state and local governments have taken steps to reduce emissions of carbon dioxide, methane and other greenhouse gases, collectively referred to as GHGs. The EPA has finalized a series of GHG monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. Also, states have imposed increasingly stringent requirement related to the venting or flaring of gas during oil and gas operations. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. Although the United States withdrew from the Paris Agreement effective November 4, 2020, President Biden issued an executive order on January 20, 2021 to rejoin the Paris Agreement, which went into effect on February 19, 2021. On April 21, 2021, the United States announced that it was setting an economy-wide target of reducing its greenhouse gas emissions by 50 to 52 percent below 2005 levels in 2030. In November 2021, in connection with the 26th Conference of the Parties in Glasgow, Scotland, the United States and other world leaders made further commitments to reduce greenhouse gas emission, including reducing global methane emissions by at least 30% by 2030 to meet this objective. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the international commitments.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely affect the oil and natural gas industry by reducing demand for hydrocarbons and by making it more expensive to develop and produce hydrocarbons, either of which could have a material adverse effect on future demand for our services. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against certain energy companies and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, climate change may cause more extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels and increased volatility in seasonal temperatures. Extreme weather conditions can interfere with our productivity and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Endangered Species Act

Environmental laws such as the Endangered Species Act, as amended, or the ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. The U.S. Fish and Wildlife Service may identify, however, previously unidentified endangered or threatened species or may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species, which could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Regulation of Hydraulic Fracturing

A portion of our business is dependent on our ability to conduct hydraulic fracturing and horizontal drilling activities. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process, which involves the injection of water, sand and chemicals (also called “proppants”) under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plans. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities and the environmental impacts of discharges from CWT facilities. Furthermore, legislation to amend the Safe Drinking Water Act, or SDWA, to repeal the exemption for hydraulic fracturing (except when diesel fuels are used) from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes New Source Performance standards, which we refer to as NSP standards, to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rules seek to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended the NSP standards to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. However, on August 13, 2019, in response to an executive order by former President Trump to review and revise unduly burdensome regulations, the EPA amended the 2012 and 2016 New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. On June 30, 2021, President Biden signed into law a joint resolution of Congress disapproving the 2020 amendments (with the exception of some technical changes) thereby reinstating the 2012 and 2016 New Source Performance standards. Additionally, on November 15, 2021, the EPA published a proposed rule that would expand and strengthen emission reduction requirements for both new and existing sources in the oil and natural gas industry by requiring increased monitoring of fugitive emissions, imposing new requirements for pneumatic controllers and tank batteries and prohibiting venting of natural gas in certain situations. These new standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. We cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

In addition, on March 26, 2015, the Bureau of Land Management, or BLM, published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. Also, on November 18, 2016, the BLM finalized a waste prevention rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. On March 28, 2017, the Trump Administration issued an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. A coalition of environmentalists, tribal advocates and the State of California filed lawsuits challenging the rule rescission. Also, on September 28, 2018, the BLM finalized revisions to the waste prevention rule to reduce "unnecessary compliance burdens". However, a federal court struck down the scaled-back rule on July 15, 2020, and shortly thereafter, on October 8, 2020, another federal court struck down the 2016 waste prevention rule. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations.

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

Several states and local jurisdictions in which we or our customers operate have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards, require the disclosure of the composition of hydraulic fracturing fluids and/or impose restrictions on the use of produced water from hydraulic fracturing activities or moratoriums on new produced water well permits in an effort to control induced seismicity. Any increased regulation of hydraulic fracturing or related activities could reduce the demand for our services and materially and adversely affect our reserves and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our customers' fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative or regulatory changes could cause us or our customers to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Regulation of Sand Proppant Services

The MSHA has primary regulatory jurisdiction over commercial silica operations, including quarries, surface mines, underground mines and industrial mineral processing facilities. MSHA representatives perform at least two annual inspections of our production facilities to ensure employee and general site safety. To date, these inspections have not resulted in any citations for material violations of MSHA standards, and we believe we are in material compliance with MSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although changes to the regulatory burden on the oil and natural gas industry could affect the demand for our services, we would not expect to be affected any differently or to any greater or lesser extent than other companies in the industry with similar operations.

Drilling. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

Federal, state and local regulations provide detailed requirements for the plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. Although the Corps does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

State Regulation. The states in which we or our customers operate regulate the drilling for, and the production and gathering of, oil and natural gas, including through requirements relating to the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may also regulate rates of production and may establish maximum daily production allowable from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but they may do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from wells and to limit the number of wells or locations our customers can drill.

In 2015, the Ohio Department of Natural Resources, or the ODNR, enacted a comprehensive set of rules to regulate the construction of well pads. Under these rules, operators must submit detailed horizontal well pad site plans certified by a professional engineer for review by the ODNR Division of Oil and Gas Resources Management prior to the construction of a well pad. These rules have resulted in increased construction costs for operators. On November 20, 2018, the Ohio EPA announced that it intends to evaluate current rules that cover air pollution emissions associated with non-conventional oil and gas facilities. The Ohio EPA is considering changes to its regulations on air quality at hydraulic fracturing and natural gas drilling sites to include compressor sites and production sites.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

OSHA Matters

We are also subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public. Compliance with these laws and regulations has not had a material adverse effect on our operations or financial position.

Employees

As of December 31, 2021, we had 783 full time employees. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Availability of Company Reports

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.mammothenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the Securities and Exchange Commission (the “SEC”) .

Risk Factors Summary

The following is a summary of the principal risks that could adversely affect our business, operations and financial results. Please refer to Item 1A “Risk Factors” of this Form 10-K below for additional discussion of the risks summarized in this Risk Factors Summary.

Risks Related to Our Business and the Industries We Serve

- Failure by PREPA to pay the amounts owed to our infrastructure subsidiary Cobra for services performed would materially and adversely affect our financial condition, results of operations and cash flows.
- Our customer base is concentrated and the loss of one or more of our significant customers, or their failure to pay the amounts they owe us, could cause our revenue to decline substantially.
- We may experience losses in excess of our recorded reserves for receivables.
- Our business and operations have been and will likely continue to be adversely affected by the COVID-19 pandemic.
- The outcomes of investigations and litigation relating to our contracts with PREPA may have a material adverse effect on our business, financial condition, results of operations and cash flows.
- Our revolving credit facility imposes, and any of our future credit facilities may impose, restrictions on us that may affect our ability to successfully operate our business.
- Our failure to receive payment for contract change orders or adequately recover on claims brought by us against customers related to payment terms and costs could materially and adversely affect our business.
- We may not accurately estimate the costs associated with infrastructure services provided under fixed price contracts, which could adversely affect our business, financial condition and cash flows.
- We may be unable to obtain sufficient bonding capacity to support certain service offerings, and the need for performance and surety bonds could reduce availability under our credit facility.
- The nature of our infrastructure services business exposes us to potential liability for warranty claims and faulty engineering, which may reduce our profitability.
- Delays and reductions in government appropriations can negatively impact energy infrastructure engineering, design, construction, maintenance and repair projects and may impair the ability of our energy infrastructure customers to timely pay for products or services provided or result in their insolvency or bankruptcy.
- Volatility in the oil and natural gas markets has negatively impacted our business in the past, and could negatively impact our oilfield services business in the future.

- Governmental laws, policies, regulations and subsidies, including initiatives to promote the use of renewable energy sources could create commodity volatility and negatively impact our oilfield services business.
- A transition of the global energy sector from primarily a fossil fuel-based system to renewable energy sources could affect our customers' level of expenditures.
- Our business depends upon our ability to obtain specialized equipment and parts from third-party suppliers, and we may be vulnerable to delayed deliveries and future price increases.
- Future performance of our natural sand proppant services business will depend on our ability to appropriately react to potential fluctuations in the demand for and supply of frac sand.
- Increasing transportation and related costs could have a material adverse effect on our business.
- Diminished access to water and inability to secure or maintain necessary permits may adversely affect operations of our frac sand processing plants.
- Development of permanent infrastructure in the Canadian oil sands region or other locations where we locate our remote accommodations could negatively impact our remote accommodations business.
- In the course of our business, we may become subject to lawsuits, indemnity or other claims, which could materially and adversely affect our business, results of operations and cash flows.
- We rely on a few key employees and skilled and qualified workers whose absence or loss could adversely affect our business.
- Our operations may be limited or disrupted in certain parts of the continental U.S. and Canada during severe weather conditions.
- Our operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could limit our ability to grow or conduct our business.
- We may have difficulties in identifying and financing suitable, accretive acquisition opportunities and integrating businesses, assets and personnel.
- Our liquidity needs could restrict our operations and make us more vulnerable to adverse economic conditions.
- Our revolving credit facility provides, and any future credit facilities may provide, for fluctuating interest rates, which may increase or decrease our interest expense.
- Our operations are subject to hazards inherent in the oil and natural gas and energy infrastructure industries, which could expose us to substantial liability and cause us to lose customers and substantial revenue.
- We are subject to extensive environmental, health and safety laws, trucking and other regulations that may subject us to increased costs and/or substantial liability.
- Our operations in our natural sand proppant services business are dependent on our rights and ability to mine our properties and on our having renewed or received the required permits and approvals from governmental authorities and other third parties.
- Changes in tax laws and regulations or adverse outcomes resulting from examination of our tax returns may adversely affect our business, results of operations, financial condition and cash flow.
- A cyber incident could occur and result in information theft or other loss, data corruption, operational disruption and/or financial loss.

Risks Inherent to Our Common Stock

- Our largest stockholder controls a significant percentage of our common stock, and its interests may conflict with those of our other stockholders.
- A significant reduction by our largest stockholder, Wexford of its ownership interests in us could adversely affect us.
- Sales of shares of our common stock by two of our largest stockholders or sales of substantial amounts of our common stock by other stockholders could adversely affect the market price of our common stock.
- The corporate opportunity provisions in our certificate of incorporation could enable Wexford or other affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.
- We have engaged and expect to continue to engage in transactions with our affiliates, the terms of which and the resolution of any conflicts thereunder may not always be in our or our stockholders' best interests.
- If our operating results do not meet expectations of securities and financial analysts, the price of our common stock could decline.
- We may issue preferred stock adversely affecting the voting power or value of our common stock.
- Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.
- The exclusive forum provisions of our certificate of incorporation could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.
- The declaration of dividends on our common stock is within the discretion of our board of directors, and there is no guarantee that we will pay any dividends in the future or at levels anticipated by our stockholders.

Item 1A. Risk Factors

Risks Related to Our Business and the Industries We Serve

Cobra, one of our infrastructure services subsidiaries, was party to service contracts with PREPA. PREPA is currently subject to bankruptcy proceedings and, as a result, PREPA's ability to meet its payment obligations under the contracts is largely dependent upon funding from the FEMA or other sources. In the event that PREPA does not pay amounts owed to us for services performed, our financial condition, results of operations and cash flows would be materially and adversely affected.

On October 19, 2017, one of our subsidiaries, Cobra, and PREPA entered into an emergency master services agreement for repairs to PREPA's electrical grid as a result of Hurricane Maria. The one-year contract, as amended, provided for payments of up to $945 million (the "first contract"). On May 26, 2018, Cobra and PREPA entered into a second one-year, $900 million master services agreement to provide additional repair services and begin the initial phase of reconstruction of the electrical power system in Puerto Rico (the "second contract"). As of December 31, 2021, PREPA owed us approximately $227.0 million for services performed excluding $110.8 million of interest charged on these delinquent balances. PREPA is currently subject to bankruptcy proceedings pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPA's ability to meet its payment obligations under the contracts is largely dependent upon funding from the FEMA or other sources. On September 30, 2019, we filed a motion with the U.S. District Court for the District of Puerto Rico seeking recovery of the amounts owed to us by PREPA, which motion was stayed by the court. On March 25, 2020, we filed an urgent motion to modify the stay order and allow our recovery of approximately $62 million in claims related to a tax gross-up provision contained in the first contract. This emergency motion was denied on June 3, 2020 and the court extended the stay of our motion. On December 9, 2020, the Court again extended the stay of our motion and directed PREPA to file a status report by June 7, 2021. On April 6, 2021, we filed a motion to lift the stay order. Following this filing, PREPA initiated discussion with Cobra, which resulted in PREPA and Cobra filing a joint motion to adjourn all deadlines relative to the April 6, 2021 motion until the June 16, 2021 omnibus hearing as a result of PREPA's understanding that FEMA would be releasing a report in the near future relating to the first contract. The joint motion was granted by the court on April 14, 2021. On May 26, 2021, FEMA issued a Determination Memorandum related to the first contract between Cobra and PREPA in which, among other things, FEMA raised two contract compliance issues and, as a result, concluded that approximately $47 million in costs were not authorized costs under the contract. On June 14, 2021, the Court issued an order adjourning Cobra's motion to lift the stay order to a hearing on August 4, 2021 and directing Cobra and PREPA to meet and confer in good faith concerning, among other things, (i) the May 26, 2021 Determination Memorandum issued by FEMA and (ii) whether and when a second determination memorandum is expected. The parties were further directed to file an additional status report, which was filed on July 20, 2021. On July 23, 2021, with our aid, PREPA filed an appeal of the entire $47 million that FEMA de-obligated in the May 26, 2021 Determination Memorandum. The appeal is currently pending. On August 4, 2021, the Court denied Cobra's April 6, 2021 motion to lift the stay order, extended the stay of our motion seeking recovery of amounts owed to Cobra and directed the parties to file an additional joint status report, which was filed on January 22, 2022. On January 26, 2022, the Court extended the stay and directed the parties to file a further status report by July 25, 2022.

We believe all amounts charged to PREPA were properly in accordance with the terms of these contracts. Further, we believe these receivables are collectible. However, in the event PREPA (i) does not have or does not obtain the funds necessary to satisfy its obligations to Cobra under the contracts, (ii) obtains the necessary funds but refuses to pay the amounts owed to us or (iii) otherwise does not pay amounts owed to us for services performed, the receivable may not be collected and our financial condition, results of operations and cash flows would be materially and adversely affected. Further, as noted above, our contracts with PREPA have concluded and we have not obtained, and there can be no assurance that we will be able to obtain, one or more contracts with other customers to replace the level of services that we provided to PREPA.

Our customer base is concentrated and the loss of one or more of our significant customers, or their failure to pay the amounts they owe us, could cause our revenue to decline substantially.

When a major customer discontinues the use our services, our revenue will decline and our operating results and financial condition will be harmed unless such loss is offset by new business. Our top five customers accounted for approximately 35% and 50%, respectively, of our revenue for the years ended December 31, 2021 and 2020. Gulfport accounted for approximately 7% of our revenue for the year ended December 31, 2021 and was our largest customer for the year ended December 31, 2020, accounting for approximately 16% of our revenue; however, our services with Gulfport ended in 2021. It is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. See the risk factors below for additional information. In addition, we are subject to credit risk due to the concentration of our customer base. In particular, PREPA owed us approximately $337.8 million (including interest charged on overdue amounts) as of December 31, 2021, as discussed in more detail below. Any nonperformance by our counterparties, including their failure to pay the amounts they owe us on a timely basis or at all, either as a result of changes in financial and economic conditions or otherwise, could have a material adverse impact on our operating results and could adversely affect our liquidity.

We may experience losses in excess of our recorded reserves for receivables.

We evaluate the collectability of our receivables based on consideration of a customer's ability to make required payments, payment history, economic events and other factors. Recorded reserves represent our estimate of current expected credit losses on existing receivables and are determined based on historical customer reviews, current financial conditions and reasonable and supportable forecasts. An unexpected change in customer financial condition or future economic uncertainty could result in additional requirements for specific reserves, which could have a material effect on our business, financial condition, results of operations and cash flows.

Our business and operations have been and will likely continue to be adversely affected by the COVID-19 pandemic.

The COVID-19 pandemic has caused, and is continuing to cause, severe disruptions in the worldwide and U.S. economy, including the global and domestic demand for oil and natural gas, which has had and is expected to continue to have an adverse effect primarily on our oilfield services business and, as a result, our financial condition, results of operations, cash flows and stock price. There continues to be many variables and uncertainties regarding the COVID-19 pandemic, including the emergence, contagiousness and threat of new and different strains of the virus and their severity; the effectiveness of treatments or vaccines against the virus or its new strains; the extent of travel restrictions, business closures and other measures that are or may be imposed in affected areas or countries by governmental authorities; disruptions in the supply chain; an increasingly competitive labor market due to a sustained labor shortage or increased turnover caused by the COVID-19 pandemic; increased logistics costs; additional costs due to remote working arrangements; adherence to social distancing guidelines; and other COVID-19-related challenges. Further, there remain increased risks of cyberattacks on information technology systems used in remote working environments; increased privacy-related risks due to processing health-related personal information; absence of workforce due to illness; the impact of the pandemic on any of our contractual counterparties; and other factors that are currently unknown or considered immaterial. It is difficult to assess the ultimate impact of the COVID-19 pandemic on our business, financial condition and cash flows.

The outcomes of investigations and litigation relating to our contracts with PREPA may have a material adverse effect on our business, financial condition, results of operations and cash flows.

On September 10, 2019, the U.S. District Court for the District of Puerto Rico unsealed an indictment that charged three individuals, including the former president of Cobra with conspiracy, wire fraud, false statements and disaster fraud. The indictment is focused on the interactions between a former FEMA official and the former President of Cobra. Neither we nor any of our subsidiaries were charged in the indictment. Subsequent to the indictment, we received (i) a preservation request letter from the SEC related to documents relevant to an ongoing investigation it is conducting and (ii) a civil investigative demand, or CID, from the United States Department of Justice, or DOJ, requesting certain documents and answers to interrogatories relevant to an ongoing investigation DOJ is conducting. Both the SEC and DOJ investigations relate to the same subjects as those at issue in the criminal matter referenced above. We are cooperating with both the SEC and DOJ investigations. Given the uncertainty inherent in the criminal proceeding and the SEC and DOJ investigations, it is not possible at this time to determine the potential outcome or other potential impacts that they will have on us. Further, government contracts are subject to various uncertainties, restrictions and regulations, including oversight audits and compliance reviews by government agencies and representatives. Accordingly, it is possible that additional investigations may arise in the future.

Opportunities associated with government contracts could lead to increased governmental regulation applicable to us.

Most government contracts are awarded through a regulated competitive bidding process. If we are successful in being awarded government contracts, significant costs could be incurred by us before any revenues were realized from these contracts. Government agencies may review a contractor's performance, cost structure and compliance with applicable laws, regulations and standards. If government agencies determine through these reviews that costs were improperly allocated to specific contracts, they will not reimburse the contractor for those costs or may require the contractor to refund previously reimbursed costs. If government agencies determine that we engaged in improper activity, we may be subject to civil and criminal penalties. Government contracts are also subject to renegotiation of profit and termination by the government prior to the expiration of the term. See the preceding risk factors for information regarding pending investigations and legal proceedings relating to our contracts with PREPA.

Our revolving credit facility imposes, and any of our future credit facilities may impose, restrictions on us that may affect our ability to successfully operate our business.

Our revolving credit facility limits, and any of our future credit facilities may limit, our ability to take various actions, such as:

- incurring additional indebtedness;
- paying dividends;
- creating certain additional liens on our assets;
- entering into sale and leaseback transactions;
- making investments;
- entering into transactions with affiliates;
- making material changes to the type of business we conduct or our business structure;
- making guarantees;
- entering into hedges;
- disposing of assets in excess of certain permitted amounts;
- merging or consolidating with other entities; and
- selling all or substantially all of our assets.

We cannot assure you that we will be able to maintain compliance with the covenants contained in our revolving credit facility as amended by the recent amendment discussed elsewhere in this report, or, if applicable, obtain a waiver of forecasted or actual non-compliance with certain financial covenants from our lenders. If an event of default occurs under our revolving credit facility and remains uncured, it could have a material adverse effect on our business, financial condition, results of operations and cash flows. The lenders (i) would not be required to lend any additional amounts to us, (ii) could elect to declare all outstanding borrowings, together with accrued and unpaid interest and fees, to be due and payable, and (iii) may have the ability to require us to apply all of our available cash to repay our outstanding borrowings.

Our failure to receive payment for contract change orders or adequately recover on claims brought by us against customers related to payment terms and costs could materially and adversely affect our financial position, results of operations and cash flows.

We have in the past brought, and may in the future bring, claims against our customers related to, among other things, the payment terms of our contracts and change orders relating to such contracts. These types of claims can occur due to, among other things, customer-caused delays or changes in project scope, both of which may result in additional costs. In some instances, these claims can be the subject of lengthy legal proceedings, and it is difficult to predict the timing and outcome of such proceedings. Our failure to promptly and adequately recover on these types of claims could have an adverse impact on our financial condition, results of operations and cash flows.

We may not accurately estimate the costs associated with infrastructure services provided under fixed price contracts, which could have an adverse effect on our financial condition, results of operations and cash flows.

We derive a portion of our infrastructure services revenue from fixed-price master service and other service agreements. Under these contracts, we typically set the price of our services on a per unit or aggregate basis and assume the risk that costs associated with our performance may be greater than what we estimated. In addition to master service and other service agreements, we enter into contracts for specific projects or jobs that may require the installation or construction of an entire infrastructure system or specified units within an infrastructure system, which are priced on a per unit basis. Profitability will be reduced if actual costs to complete a project exceed our original estimates. Our profitability is dependent upon our ability to accurately estimate the costs associated with our services and our ability to execute in accordance with our plans. A variety of factors could negatively affect these costs, such as lower than anticipated productivity, conditions at work sites differing materially from those anticipated at the time we bid on the contract and higher than expected costs of materials and labor. These variations, along with other risks inherent in performing fixed price contracts, could cause actual project revenue and profits to differ from original estimates, which could result in lower margins than anticipated, or losses, which could reduce our profitability, cash flows and liquidity.

We may be unable to obtain sufficient bonding capacity to support certain service offerings, and the need for performance and surety bonds could reduce availability under our credit facility.

Some of our infrastructure services contracts require performance and payment bonds. If we are not able to renew or obtain a sufficient level of bonding capacity in the future, we may be precluded from being able to bid for certain contracts or successfully contract with certain customers. In addition, even if we are able to successfully renew or obtain performance or payment bonds, we may be required to post letters of credit in connection with the bonds, which would reduce availability under our credit facility. Furthermore, under standard terms in the surety market, sureties issue bonds on a project-by-project basis and can decline to issue bonds at any time or require the posting of additional collateral as a condition to issuing or renewing any bonds. If we were to experience an interruption or reduction in the availability of bonding capacity as a result of these or any other reasons, we may be unable to compete for or work on projects that require bonding.

The nature of our infrastructure services business exposes us to potential liability for warranty claims and faulty engineering, which may reduce our profitability.

Under some of our infrastructure services contracts with customers, we provide a warranty for the services we provide, guaranteeing the work performed against defects in workmanship and material. As much of the work we perform is inspected by our customers for any defects in construction prior to acceptance of the project, we have not historically incurred warranty claims. Additionally, materials used in construction are often provided by the customer or are warranted against defects from the supplier. However, certain projects may have longer warranty periods and include facility performance warranties that may be broader than the warranties we generally provide. In these circumstances, if warranty claims occurred, it could require us to re-perform the services or to repair or replace the warranted item, at a cost to us, and could also result in other damages if we are not able to adequately satisfy our warranty obligations. In addition, we may be required under contractual arrangements with our customers to warrant any defects or failures in materials we provide that we purchase from third parties. While we generally require suppliers to provide us warranties that are consistent with those we provide to the customers, if any of these suppliers default on their warranty obligations to us, we may incur costs to repair or replace the defective materials for which we are not reimbursed. Costs incurred as a result of warranty claims could adversely affect our financial condition, results of operations and cash flows.

Our infrastructure services business involves professional judgments regarding the planning, design, development, construction, operations and management of electric power transmission and commercial construction. Because our projects are often technically complex, our failure to make judgments and recommendations in accordance with applicable professional standards, including engineering standards, could result in damages. While we do not generally accept liability for consequential damages, and although we have adopted a range of insurance, risk management and risk avoidance programs designed to reduce potential liabilities, a significantly adverse or catastrophic event at one of our project sites or completed projects resulting from the services we have performed could result in significant warranty, professional liability, or other claims against us as well as reputational harm, especially if public safety is impacted. These liabilities could exceed our insurance limits or could impact our ability to obtain insurance in the future. In addition, customers, subcontractors or suppliers who have agreed to indemnify us against any such liabilities or losses might refuse or be unable to pay us. An uninsured claim, either in part or in whole, if successful and of a material magnitude, could have a substantial impact on our business, financial condition, results of operations and cash flows.

The timing of new contracts and termination of existing contracts may result in unpredictable fluctuations in our cash flows and financial results.

A substantial portion of our continental United States-based infrastructure services revenue is derived from project-based work that is awarded through a competitive bid process. It is generally very difficult to predict the timing and geographic distribution of the projects that we will be awarded. The selection of, timing of, or failure to obtain projects, delays in awards of projects, the re-bidding or termination of projects due to budget overruns, cancellations of projects or delays in completion of contracts could result in the under-utilization of our assets, which could lower our overall profitability and reduce our cash flows. Even if we are awarded contracts, we face additional risks that could affect whether, or when, work will begin. This can present difficulty in matching workforce size and equipment location with contract needs. In some cases, we may be required to bear the cost of a ready workforce and equipment that is larger than necessary, which could impact our cash flow, expenses and profitability. If an expected contract award or the related work release is delayed or not received, we could incur substantial costs without receipt of any corresponding revenues. Moreover, construction projects for which our services are contracted may require significant expenditures by us prior to receipt of relevant payments from the customer. Finally, the winding down or completion of work on significant projects that were active in previous periods will reduce our revenue and earnings if such significant projects have not been replaced in the current period.

Many of our contracts may be canceled upon short notice, typically 30 to 90 days, even if we are not in default under the contract, and we may be unsuccessful in replacing our contracts if they are canceled or as they are completed or expire. We could experience a decrease in our revenue, net income and liquidity if contracts are canceled and if we are unable to replace canceled, completed or expired contracts. Certain of our infrastructure services customers assign work to us on a project-by-project basis under MSAs. Under these agreements, our customers often have no obligation to assign a specific amount of work to us. Our operations could decline significantly if the anticipated volume of work is not assigned to us or is canceled. Many of our contracts, including our MSAs, are opened to competitive bid at the expiration of their terms. There can be no assurance that we will be the successful bidder on our existing contracts that come up for re-bid.

Delays and reductions in government appropriations can negatively impact energy infrastructure engineering, design, construction, maintenance and repair projects and may impair the ability of our energy infrastructure customers to timely pay for products or services provided or result in their insolvency or bankruptcy, any of which exposes us to credit risk of our infrastructure customers.

Many of our infrastructure customers derive funding from federal, state and local bodies. Delayed or reduced appropriations may cancel, curtail or delay projects and may have an adverse effect on our business, results of operations, cash flows and financial condition.

A portion of our business depends on the oil and natural gas industry and particularly on the level of exploration and production activity within the United States and Canada, and the sharp decline in oil prices in 2020 and continued volatility in the oil and natural gas markets have negatively impacted, and are likely to continue to negatively impact, our oilfield services and, as a result, our business, financial condition, results of operations, cash flows and stock price.

Demand for our oil and natural gas products and services depends substantially on the level of capital expenditures by companies in the oil and natural gas industry. In early March 2020, oil prices dropped sharply and then continued to decline reaching levels below zero dollars per barrel. This was a result of multiple factors affecting global oil and natural gas markets, including the announcement of price reductions and production increases by OPEC members and other oil exporting nations and the ongoing COVID-19 pandemic. Although commodity prices have generally recovered, they are expected to continue to be volatile as a result of production levels, inventories and demand, and national and international economic performance. Other significant factors that are likely to continue to affect commodity prices in current and future periods include, but are not limited to, the effect of U.S. energy, monetary and trade policies, U.S. and global political developments, the impact and duration of the ongoing COVID-19 pandemic and conditions in the U.S. oil and gas industry, actions of OPEC+ members, the impact of the current Russian/Ukrainian military conflict on the global energy and capital markets and global stability and other factors. We anticipate demand for our oil and natural gas services and products will continue to be dependent on the level of capital expenditures by companies in the oil and natural gas industry and, ultimately, commodity prices. While we still expect commodity prices to be the primary driver of capex spending and industry activity levels in the future, other factors, such as debt repayment obligations and access to the capital markets, may play a significant role in the ultimate level of capex spend by the companies that use our completion and production, natural sand proppant and contract land and directional drilling service lines. Industry conditions are dynamic and the weakening of commodity prices from current levels may result in a material adverse impact on certain of our customers' liquidity and financial position resulting in spending reductions, delays in the collection of amounts owing to us and similar impacts. These conditions, and others, have had and may continue to have an adverse impact on our financial condition, results of operations and cash flows, and it is difficult to predict how long the current commodity price environment will continue.

Many factors over which we have no control affect the supply of and demand for, and our customers' willingness to explore, develop and produce oil and natural gas, and therefore, influence prices for our products and services, including:

- the domestic and foreign supply of and demand for oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected decline rates of current production;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia, including the impact of the current Russian/Ukrainian military conflict on the global energy and capital markets and global stability;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- the discovery rates of new oil and natural gas reserves;
- contractions in the credit market;

- the strength or weakness of the U.S. dollar;
- available pipeline and other transportation capacity;
- the levels of oil and natural gas storage;
- weather conditions and other natural disasters;
- political instability in oil and natural gas producing countries;
- domestic and foreign tax policy;
- domestic and foreign governmental approvals and regulatory requirements and conditions;
- the continued threat of terrorism and the impact of military and other action, including military action in the Middle East;
- technical advances affecting energy consumption;
- the proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels;
- the ability of oil and natural gas producers to raise equity capital and debt financing;
- global or national health concerns, including the outbreak of pandemic or contagious diseases such as the coronavirus;
- merger and divestiture activity among oil and natural gas producers; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Any of the above factors could impact the level of oil and natural gas exploration and production activity and could ultimately have a material adverse effect on our business, financial condition, results of operations and cash flows. Further, future weakness in commodity prices could impact our business going forward, and we could encounter difficulties such as an inability to access needed capital on attractive terms or at all, recognizing asset impairment charges, an inability to meet financial ratios contained in our debt agreements, a need to reduce our capital spending and other similar impacts.

The cyclicality of the oil and natural gas industry may cause our operating results to fluctuate.

We derive a portion of our revenues from companies in the oil and natural gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility of oil and natural gas prices. We have, and may in the future, experience significant fluctuations in operating results as a result of the reactions of our customers to changes in oil and natural gas prices. For example, prolonged low commodity prices experienced by the oil and natural gas industry during the first half of 2020, combined with the ongoing COVID-19 pandemic, adverse changes in demand for our services and volatility in the capital and credit markets, caused many exploration and production companies to reduce their capital budgets and drilling activity. This resulted in a significant decline in demand for oilfield services and adversely impacted the prices oilfield services companies could charge for their services. In addition, a majority of the service revenue we earn is based upon a charge for a relatively short period of time (e.g., an hour, a day, a week) for the actual period of time the service is provided to our customers. By contracting services on a short-term basis, we are exposed to the risks of a rapid reduction in market prices and utilization, with resulting volatility in our revenues.

If oil prices or natural gas prices decline, the demand for our oil and natural gas services could be adversely affected.

The demand for our oil and natural gas services is primarily determined by current and anticipated oil and natural gas prices and the related general production spending and level of drilling activity in the areas in which we have operations. Volatility or weakness in oil prices or natural gas prices (or the perception that oil prices or natural gas prices will decrease) affects the spending patterns of our customers and may result in the drilling of fewer new wells or lower production spending on existing wells. This, in turn, could result in lower demand for our services and may cause lower rates and lower utilization of our well service equipment.

Any future decline in oil and gas prices could materially affect the demand for our services. Prices for oil and natural gas historically have been extremely volatile and are expected to continue to be volatile in the years to come. During 2021, West Texas Intermediate posted prices ranged from $47.62 to $84.65 per barrel and the New York Mercantile Exchange natural gas futures prices ranged from $2.45 to $5.26 per MMBtu. If the prices of oil and natural gas decline from current levels, our operations, financial condition and level of expenditures may be materially and adversely affected.

Failure to effectively and timely address the energy transition to a lower carbon footprint could adversely affect our oil and gas business

Our long-term success depends on our ability to effectively address the energy transition to a lower carbon footprint, which will require adapting our portfolio of oilfield services to potentially changing or more burdensome government requirements and customer preferences. If the energy industry transition changes faster than anticipated or in a manner that we do not anticipate, demand for oilfield services could be adversely affected. Furthermore, if we fail or are perceived to not effectively implement an energy transition strategy, or if investors or financial institutions shift funding away from companies in fossil fuel related industries, our business, access to capital and the market for our securities could be negatively impacted.

Deterioration of the commodity price environment can negatively impact oil and natural gas exploration and production companies and, in some cases, impair their ability to timely pay for products or services provided or result in their insolvency or bankruptcy, any of which exposes us to credit risk of our oil and natural gas exploration and production customers.

In certain economic and commodity price environments, we may experience increased difficulties, delays or failures in collecting outstanding receivables from our customers, due to, among other reasons, a reduction in their cash flow from operations, their inability to access the credit markets and, in certain cases, their insolvencies. Such increases in collection issues could have a material adverse effect on our business, results of operations, cash flows and financial condition. We cannot assure you that the reserves we have established for potential credit losses will be sufficient to meet write-offs of uncollectible receivables or that our losses from such receivables will be consistent with our expectations. To the extent one or more of our key customers commences bankruptcy proceedings, as was the case with Gulfport, our contracts with these customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could also have a material adverse effect on our business, results of operations, cash flows and financial condition.

Shortages, delays in delivery and interruptions in supply of drill pipe, replacement parts, other equipment, supplies and materials may adversely affect our drilling business or our pressure pumping business.

During periods of increased demand for drilling and completion services, the industry has experienced shortages of drill pipe, replacement parts, other equipment, supplies and materials, including, in the case of our pressure pumping operations, replacement parts, other equipment, proppants, acid, gel and water. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. In addition, any interruption in supply could result in significant delays in delivery of equipment and materials or prevent operations. Interruptions may be caused by, among other reasons:

- weather issues, whether short-term such as a hurricane, or long-term such as a drought; and
- shortage in the number of vendors able or willing to provide the necessary equipment, supplies and materials, including as a result of commitments of vendors to other customers or third parties.

These price increases, delays in delivery and interruptions in supply may require us to increase capital and repair expenditures and incur higher operating costs. Severe shortages, delays in delivery and interruptions in supply could limit our ability to construct and operate our drilling rigs or pressure pumping fleets and could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Oilfield services equipment, refurbishment and new asset construction projects, as well as the reactivation of oilfield service assets that have been idle for six months or longer, are subject to risks which could cause delays or cost overruns and adversely affect our business, cash flows, results of operations and financial position.

Oilfield services equipment or assets being upgraded, converted or re-activated following a period of inactivity may experience significant start-up costs and complications and may encounter other operational problems that could result in significant delays, uncompensated downtime, reduced dayrates or the cancellation, termination or non-renewal of contracts. In this regard, due to market conditions, we have temporarily shut down certain of our service offerings, including contract land drilling, flowback, cementing, acidizing and crude oil hauling operations as well as certain of our facilities, such as our sand processing plant in Pierce County, Wisconsin. Further, construction and upgrade projects are subject to risks of delay or significant cost overruns inherent in any large construction project from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment or shipyard construction;
- failure of equipment to meet quality and/or performance standards;
- financial or operating difficulties of equipment vendors;

- unanticipated actual or purported change orders;
- inability by us or our customers to obtain required permits or approvals, or to meet applicable regulatory standards in our areas of operations;
- unanticipated cost increases between order and delivery;
- adverse weather conditions and other events of force majeure;
- design or engineering changes; and
- work stoppages and other labor disputes.

The occurrence of any of these events could have a material adverse effect on our business, cash flows, results of operations and financial position.

Advancements in oilfield service technologies could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The oilfield services industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As new horizontal and directional drilling, pressure pumping, pressure control and well service technologies develop, we may be placed at a competitive disadvantage, and competitive pressure may force us to implement new technologies at a substantial cost. We may not be able to successfully acquire or use new technologies. Further, our customers are increasingly demanding the services of newer, higher specification drilling rigs. There can be no assurance that we will:

- have sufficient capital resources to build new, technologically advanced equipment and other assets;
- successfully integrate additional oilfield service equipment and other assets;
- effectively manage the growth and increased size of our organization, equipment and other assets;
- successfully deploy idle, stacked or additional oilfield service assets;
- maintain crews necessary to operate additional drilling rigs or pressure pumping service equipment; or
- successfully improve our financial condition, results of operations, business or prospects.

If we are not successful in building or acquiring new oilfield service equipment and other assets or upgrading our existing rigs and equipment in a timely and cost-effective manner, we could lose market share. New technologies, services or standards could render some of our services, equipment and other assets obsolete, which could have a material adverse impact on our business, cash flows, results of operations and financial condition.

Our business depends upon our ability to obtain specialized equipment and parts from third-party suppliers, and we may be vulnerable to delayed deliveries and future price increases.

We purchase specialized equipment and parts from third party suppliers. At times during the business cycle, there is a high demand for hydraulic fracturing, coiled tubing and other oilfield services and extended lead times to obtain equipment needed to provide these services. Further, there are a limited number of suppliers that manufacture the equipment we use. Should our current suppliers be unable or unwilling to provide the necessary equipment and parts or otherwise fail to deliver the products timely and in the quantities required, any resulting delays in the provision of our services could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, future price increases for this type of equipment and parts could negatively impact our ability to purchase new equipment to update or expand our existing fleet or to timely repair equipment in our existing fleet.

An increase in the prices of certain materials used in our businesses could adversely affect our business, financial condition, results of operation and cash flows.

We are exposed to market risk of increases in certain commodity prices of materials, such as copper and steel, which are used as components of supplies or materials utilized in some of our infrastructure and pressure pumping businesses. An increase in these materials could increase our operating costs, limit our ability to service our customers' needs or otherwise materially and adversely affect our business, financial condition, results of operation and cash flows.

Inaccuracies in estimates of volumes and qualities of our sand reserves could result in lower than expected sales and higher than expected production costs.

Estimates of our sand reserves are by nature imprecise and depend to some extent on statistical inferences drawn from available data, which may prove unreliable. There are numerous uncertainties inherent in estimating quantities and qualities of sand reserves and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable sand reserves necessarily depend on a number of factors and assumptions, all of which may vary considerably from actual results, such as:

- geological and mining conditions and/or effects from prior mining that may not be fully identified by available data or that may differ from experience;
- assumptions concerning future prices of frac sand, operating costs, mining technology improvements, development costs and reclamation costs; and
- assumptions concerning future effects of regulation, including the issuance of required permits and taxes by governmental agencies.

Any inaccuracy in the estimates related to our sand reserves could result in lower than expected sales and higher than expected costs. For example, these estimates assume that our revenue and cost structure will remain relatively constant over the life of our reserves. If these assumptions prove to be inaccurate, some or all of our reserves may not be economically mineable, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, our current customer contracts require us to deliver frac sand that meets certain specifications. If the estimates of the quality of our sand reserves, including the volumes of the various specifications of those reserves, prove to be inaccurate, we may incur significantly higher excavation costs without corresponding increases in revenues, we may not be able to meet our contractual obligations, or our facilities may have a shorter than expected reserve life, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

As part of our natural sand proppant services business, we rely on third parties for raw materials and transportation, and the suspension or termination of our relationship with one or more of these third parties could adversely affect our business, financial conditions, results of operations and cash flows.

As part of our natural sand proppant services business, we mine and process sand into premium monocrystalline sand, a specialized mineral that is used as a proppant (also known as frac sand) at our Barron County and Jackson County, Wisconsin plants. We also buy processed sand from suppliers on the spot market. In addition, we also buy raw or washed sand and process it at our indoor sand processing plant located in Pierce County, Wisconsin. We sell natural sand proppant to our customers for use in their hydraulic fracturing operations to enhance the recovery rates of hydrocarbons from oil and natural gas wells. We also provide logistics solutions to deliver our frac sand products to our customers. Because our customers generally find it impractical to store frac sand in large quantities near their job sites, they seek to arrange for product to be delivered where and as needed, which requires predictable and efficient loading and shipping of product. To facilitate our logistics and transload facility capabilities, we contract with third party providers to transport our frac sand products to railroad facilities for delivery to our customers. We also lease a railcar fleet from various third parties to deliver our frac sand products to our customers and lease or otherwise utilize origin and destination transloading facilities. The suspension, termination or nonrenewal of our relationship with any one or more of these third parties involved in the sourcing, transportation and delivery of our frac sand products could result in material operational delays, increase our operating costs, limit our ability to service our customers' wells or otherwise materially and adversely affect our business, financial condition, results of operations and cash flows.

Future performance of our natural sand proppant services business will depend on our ability to succeed in competitive markets, and on our ability to appropriately react to potential fluctuations in the demand for and supply of frac sand.

In our natural sand proppant services business, we operate in a highly competitive market that is characterized by a small number of large, national producers and a larger number of small, regional or local producers. Competition in the industry is based on price, consistency and quality of product, site location, distribution and logistics capabilities, customer service, reliability of supply and breadth of product offering. The large, national producers with whom we compete include Badger Mining Corporation, Covia Holdings Corporation, Hi-Crush Partners LP, Smart Sand, Inc. and U.S. Silica Holdings Inc. Our larger competitors may have greater financial and other resources than we do, may develop technology superior to ours, may have production facilities that are located closer to sand mines from which raw sand is mined or to their key customers than our facilities or have a more cost effective access to raw sand and transportation facilities than we do. As the demand for hydraulic fracturing services has decreased due to commodity price volatility, prices in the frac sand market have materially decreased as demand for frac sand dropped and sand producers sought to preserve market share or exit the market and sell frac sand at below market prices. In addition, some oil and natural gas exploration and production companies and other providers of hydraulic fracturing services have acquired their own frac sand reserves, developed or expanded frac sand production capacity or otherwise fulfilled their own proppant requirements and existing or new frac sand producers could add to or expand their frac sand production capacity, which may negatively impact pricing and demand for our frac sand. We may not be able to compete successfully against either our larger or smaller competitors in the future, and competition could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Demand for our frac sand products could be reduced by changes in well stimulation processes and technologies, as well as changes in governmental regulations and other applicable law.

As part of our natural sand proppant services business, we mine, process and sell frac sand products to our customers for use in their hydraulic fracturing operations to enhance the recovery rates of hydrocarbons from oil and natural gas wells. A significant shift in demand from frac sand to other proppants, or the development of new processes to replace hydraulic fracturing altogether, could cause a decline in the demand for the frac sand we produce and result in a material adverse effect on our business, financial condition, results of operations and cash flows. Further, federal and state governments and agencies have adopted various laws and regulations or are evaluating proposed legislation and regulations that are focused on the extraction of shale gas or oil using hydraulic fracturing, a process which utilizes proppants such as those that we produce. Future hydraulic fracturing-related legislation or regulations could restrict the ability of our customers to utilize, or increase the cost associated with, hydraulic fracturing, which could reduce demand for our proppants and adversely affect our business, financial condition, results of operations and cash flows. For additional information regarding the regulation of hydraulic fracturing, see Item 1. Business—Regulation of Hydraulic Fracturing included elsewhere in this annual report.

We face distribution and logistics challenges in our business.

In response to various factors, including fluctuations in oil and natural gas prices, our customers may shift their focus among resource plays, some of which can be located in geographic areas that do not have well-developed transportation and distribution infrastructure systems. Some geographic areas, including the areas in which our sand facilities are located, have limited access to railroads. Any interruption or delay in the railroad access or service may affect our ability to ship and/or the timing of shipment of our frac sand to our customers, which may adversely affect our revenues or result in increased costs, and thus could negatively impact our results of operations and financial condition. Serving our customers in these less-developed areas presents distribution and other operational challenges that may affect our sales and could negatively impact our operating costs. Labor disputes, system constraints, derailments, adverse weather conditions or other environmental events, an increasingly tight railcar leasing market and changes to rail freight systems, among other factors, could interrupt or limit available transportation services, could affect our ability to timely and cost-effectively deliver our frac sand to our customers and could provide a competitive advantage to our competitors located in closer proximity to our customers. Failure to find long-term solutions to these logistics challenges could adversely affect our business, financial condition, results of operations and cash flows.

Increasing transportation and related costs could have a material adverse effect on our business.

Because of the relatively low cost of producing frac sand, transportation expenses and related costs, including freight charges, fuel surcharges, transloading fees, switching fees, railcar lease costs, demurrage costs and storage fees, comprise a significant component of the total delivered cost of frac sand sales. The relatively high transportation expenses and related costs tend to favor frac sand producers located in close proximity to their customers. If and when we expand our frac sand production, our need for additional transportation services and transload network access will increase. We contract with truck and rail services to move frac sand from our production facilities to transload sites and our customers, and increased costs under these contracts could adversely affect our results of operations. In addition, we bear the risk of non-delivery under our contracts. A significant increase in transportation service rates, a reduction in the dependability or availability of transportation or transload services, or relocation of our customers' businesses to areas farther from our plants or transloading facilities could impair our ability to deliver our products economically to our customers and our ability to expand into different markets.

Diminished access to water and inability to secure or maintain necessary permits may adversely affect operations of our frac sand processing plants.

The processing of raw sand and production of natural sand proppant require significant amounts of water. As a result, securing water rights and water access is necessary to operate our processing facilities. If the areas where our facilities are located experience water shortages, restrictions or any other constraints due to drought, contamination or otherwise, there may be additional costs associated with securing water access. Although we have obtained water rights to service our activities when we are operating our processing plants, the amount of water that we are entitled to use pursuant to our water rights must be determined by the appropriate regulatory authorities. Such regulatory authorities may amend the regulations regarding such water rights, increase the cost of maintaining such water rights or eliminate our current water rights, and we may be unable to retain all or a portion of such water rights. If implemented, these new regulations could also affect local municipalities and other industrial operations and could have a material adverse effect on costs involved in operating our processing plant. Such changes in laws, regulations or government policy and related interpretations pertaining to water rights may alter the environment in which we do business, which may have an adverse effect on our business, financial condition, results of operations and cash flows. Additionally, a water discharge permit may be required to properly dispose of water at our processing sites when in operation. Certain of our facilities are also required to obtain storm water permits. The water discharge, storm water or any other permits we may be required to have in order to conduct our frac sand processing operations is subject to regulatory discretion, and any inability to obtain or maintain the necessary permits could have an adverse effect on our ability to run such operations.

Similar to our natural sand proppant services, certain of our completion and production services, particularly our hydraulic fracturing services, are substantially dependent on the availability of water. Restrictions on our ability, or our customers' ability, to obtain water may have an adverse effect on our business, financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. In recent years, certain areas in which we operate have experienced drought conditions and competition for water in such areas is growing. As a result, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. Our inability, or customers' inability, to obtain water to use in our operations from local sources or to effectively utilize flowback water could have an adverse effect on our business, financial condition, results of operations and cash flows.

The customized nature, and remote location, of the modular camps that we provide and service present unique challenges that could adversely affect our ability to successfully operate our remote accommodations business.

We rely on a third-party subcontractor to manufacture and install the customized modular units used in our remote accommodations business. These customized units often take a considerable amount of time to manufacture and, once manufactured, often need to be delivered to remote areas that are frequently difficult to access by traditional means of transportation. In the event we are unable to provide these modular units in a timely fashion, we may not be entitled to full, or any, payment therefor under the terms of our contracts with customers. In addition, the remote location of the modular camps often makes it difficult to install and maintain the units, and our failure, on a timely basis, to have such units installed and provide maintenance services could result in our breach of, and non-payment by our customers under, the terms of our customer contracts. Any of these factors could have a material adverse effect on our remote accommodation business and our overall financial condition and results of operations.

Health and food safety issues and food-borne illness concerns could adversely affect our remote accommodations business.

We provide food services to our customers as part of our remote accommodations business and, as a result, face health and food safety issues that are common in the food and hospitality industries. Food-borne illnesses, such as E. coli, hepatitis A, trichinosis or salmonella, and food safety issues have occurred in the food industry in the past and could occur in the future. Our reliance on third-party food suppliers and distributors increases the risk that food-borne illness incidents could be caused by factors outside of our control. New illnesses resistant to any precautions may develop in the future, or diseases with long incubation periods could arise. Further, the remote nature of our accommodation facilities and related food services may increase the risk of contamination of our food supply and create additional health and hygiene concerns due to the limited access to modern amenities and conveniences that may not be faced by other food service providers or hospitality businesses operating in an urban environment. If our customers become ill from food-borne illness, we could be forced to close some or all of our remote accommodation facilities on a temporary basis or otherwise. Any such incidents and/or any report of publicity linking us to incidents of food-borne illness or other food safety issues, including food tampering or contamination, could adversely affect our remote accommodations business as well as our overall financial condition and results of operations.

Development of permanent infrastructure in the Canadian oil sands region or other locations where we locate our remote accommodations could negatively impact our remote accommodations business.

Our remote accommodations business specializes in providing modular housing and related services for workforces in remote areas which lack the infrastructure typically available in towns and cities. If significant development activity does not return to the Canadian oil sands region or if permanent towns, cities and municipal infrastructure develop in the oil sands region of northern Alberta, Canada or other regions where we locate our modular camps, then demand for our accommodations could decrease as customer employees move to the region and choose to utilize permanent housing and food services.

Revenue generated and expenses incurred by our remote accommodation business are denominated in the Canadian dollar and could be negatively impacted by currency fluctuations.

Our remote accommodation business generates revenue and incurs expenses that are denominated in the Canadian dollar. These transactions could be materially affected by currency fluctuations. Changes in currency exchange rates could adversely affect our combined results of operations or financial position. We also maintain cash balances denominated in the Canadian dollar. At December 31, 2021, we had $1.5 million of cash in Canadian dollars, in Canadian accounts. We have not hedged our exposure to changes in foreign currency exchange rates and, as a result, could incur unanticipated translation gains and losses.

In the course of our business, we may become subject to lawsuits, indemnity or other claims, which could materially and adversely affect our business, results of operations and cash flows.

In addition to the investigations and legal proceedings referenced in the risk factors above, from time to time, we are subject to various claims, lawsuits and other legal proceedings brought or threatened against us in the course of our business. These actions and proceedings may seek, among other things, compensation for alleged personal injury, workers' compensation, employment discrimination and other employment-related damages, breach of contract, indemnity claims, property damage and violation of federal or state securities laws. We may also be subject to litigation in the normal course of business involving allegations of violations of the Fair Labor Standards Act and state wage and hour laws.

Claimants may seek large damage awards and defending claims can involve significant costs. When appropriate, we establish accruals for litigation and contingencies that we believe to be adequate in light of current information, legal advice and our indemnity insurance coverages. We reassess our potential liability for litigation and contingencies as additional information becomes available and adjust our accruals as necessary. We could experience a reduction in our profitability and liquidity if we do not properly estimate the amount of required accruals for litigation or contingencies, or if our insurance coverage proves to be inadequate or becomes unavailable, or if our self-insurance liabilities are higher than expected. The outcome of litigation is difficult to assess or quantify, as plaintiffs may seek recovery of very large or indeterminate amounts and the magnitude of the potential loss may remain unknown for substantial periods of time. Furthermore, because litigation is inherently uncertain, the ultimate resolution of any such claim, lawsuit or proceeding through settlement, mediation, or court judgment could have a material adverse effect on our business, financial condition or results of operations. In addition, claims, lawsuits and proceedings may harm our reputation or divert management's attention from our business or divert resources away from operating our business, and cause us to incur significant expenses, any of which could have a material adverse effect on our business, financial condition, results of operations and cash flows. Please see Note 19. Commitments and Contingencies to our consolidated financial statements elsewhere in this annual report.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of our Chief Executive Officer or Chief Financial Officer could disrupt our operations. We do not have any written employment agreement with either our Chief Executive Officer or our Chief Financial Officer at this time. Further, we do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

If we are unable to employ a sufficient number of skilled and qualified workers, our capacity and profitability could be diminished and our growth potential could be impaired.

The delivery of our products and services requires skilled and qualified workers with specialized skills and experience who can perform physically demanding work. As a result of the volatility of the energy services industry and the demanding nature of the work, workers may choose to pursue employment in fields that offer a more desirable work environment at wage rates that are competitive. Our ability to be productive and profitable will depend upon our ability to employ and retain skilled workers. In addition, our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers is high, and the supply is limited. As a result, competition for experienced energy service personnel is intense, and we face significant challenges in competing for crews and management with large and well established competitors. A significant increase in the wages paid by competing employers could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired, particularly as our workforce has been significantly reduced over the past several years due to the lack of pyament from PREPA and the downturn in our business.

Unionization efforts could increase our costs or limit our flexibility.

Presently, none of our employees work under collective bargaining agreements. Unionization efforts have been made from time to time within our industries, to varying degrees of success. Any such unionization could increase our costs or limit our flexibility.

Our operations may be limited or disrupted in certain parts of the continental U.S. and Canada during severe weather conditions, which could have a material adverse effect on our financial condition and results of operations.

We provide well completion services and drilling services in the Utica, SCOOP, STACK, Permian Basin, Marcellus, Granite Wash, and Cana Woodford resource plays located in the continental U.S. We provide infrastructure services in the northeast, southwest and midwest portions of the United States. We provide remote accommodation services in the oil sands in Alberta, Canada. We serve these markets through our facilities and service centers located in Ohio, Oklahoma, Texas, Wisconsin, Minnesota, Kentucky, California and Alberta, Canada. For the years ended December 31, 2021 and 2020, we generated approximately 48% and 35%, respectively, of our revenue from our operations in Ohio, Wisconsin, Minnesota, North Dakota, Pennsylvania, West Virginia and Canada where weather conditions may be severe, particularly during winter and spring months. Repercussions of severe weather conditions may include:

- curtailment of services;
- weather-related damage to equipment resulting in suspension of operations;
- weather-related damage to our facilities;
- inability to deliver equipment and materials to jobsites in accordance with contract schedules; and
- loss of productivity.

Many municipalities, including those in Ohio and Wisconsin, impose bans or other restrictions on the use of roads and highways, which include weight restrictions on the paved roads that lead to our jobsites due to the muddy conditions caused by spring thaws. This can limit our access to these jobsites and our ability to service wells in these areas. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs in those regions. Weather conditions may also affect the price of crude oil and natural gas, and related demand for our services. Any of these factors could have a material adverse effect on our financial condition and results of operations.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets and global or national health concerns have contributed to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have in the past precipitated and may in the future precipitate an economic slowdown. Concerns about global economic growth may have a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids can be sold, which could affect the ability of our customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

A terrorist attack or armed conflict could harm our business.

The occurrence or threat of terrorist attacks in the United States or other countries, anti-terrorist efforts and other armed conflicts involving the United States or other countries, including continued hostilities in the Middle East, may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could limit our ability to grow.

Our capital budget for 2022 is estimated to be $6 million, depending upon industry conditions and our financial results. We fund our capital expenditures primarily with cash generated by operations, borrowings under our revolving credit facility and sale-leaseback transactions. We may be unable to generate sufficient cash from operations and other capital resources to meet our operating needs and/or maintain planned or future levels of capital expenditures which, among other things, may prevent us from acquiring new equipment, properly maintaining our existing equipment or restarting idled businesses or expanding existing operations as demand may warrant. Also, on February 28, 2022, our revolving credit facility was amended to, among other things, provide for a reduction in the maximum revolving advance amount in an amount equal to 50% of

PREPA claims proceeds, subject to a floor equal to the sum of eligible billed and unbilled accounts receivables and, as a result, as of March 2, 2022, we had approximately $11 million of available borrowing capacity under our amended revolving credit facility. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Our Revolving Credit Facility. Further, any disruptions or continuing volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. This could put us at a competitive disadvantage, impair our ability to meet our operating needs or interfere with our growth plans. Further, our actual capital expenditures for 2022 or future years could exceed our capital expenditure budget. In the event our operating or capital expenditure requirements at any time are greater than the amount we have available, we could be required to seek additional sources of capital, which may include debt financing, joint venture partnerships, sales of assets, sale-leaseback transactions, offerings of debt or equity securities or other means. We may not be able to obtain any such alternative source of capital. We may be required to curtail or eliminate contemplated activities. If we can obtain alternative sources of capital, the terms of such alternative may not be favorable to us. In particular, the terms of any debt financing may include covenants that significantly restrict our operations. Our inability to grow as planned may reduce our chances of achieving, maintaining and improving profitability.

The growth of our business through acquisitions may expose us to various risks, including those relating to difficulties in identifying suitable, accretive acquisition opportunities and integrating businesses, assets and personnel, as well as difficulties in obtaining financing for targeted acquisitions and the potential for increased leverage or debt service requirements.

As a component of our business strategy, we have pursued and intend to continue to pursue selected, accretive acquisitions of complementary assets, businesses and technologies. Acquisitions involve numerous risks, including:

- unanticipated costs and assumption of liabilities and exposure to unforeseen liabilities of acquired businesses, including but not limited to environmental liabilities;
- difficulties in integrating the operations and assets of the acquired business and the acquired personnel;
- limitations on our ability to properly assess and maintain an effective internal control environment over an acquired business, in order to comply with public reporting requirements;
- potential losses of key employees and customers of the acquired businesses;
- inability to commercially develop acquired technologies;
- risks of entering markets in which we have limited prior experience; and
- increases in our expenses and working capital requirements.

The process of integrating an acquired business may involve unforeseen costs and delays or other operational, technical and financial difficulties and may require a disproportionate amount of management attention and financial and other resources. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. Furthermore, there is intense competition for acquisition opportunities in our industries. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. We may incur substantial indebtedness to finance future acquisitions and also may issue equity, debt or convertible securities in connection with such acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity or convertible securities could be dilutive to our existing stockholders. Furthermore, we may not be able to obtain additional financing on satisfactory terms. Even if we have access to the necessary capital, we may be unable to continue to identify additional suitable acquisition opportunities, negotiate acceptable terms or successfully acquire identified targets. Our ability to grow through acquisitions and manage growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

Growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand the scope of our activities, lines of our businesses and our geographic coverage through both organic growth and acquisitions, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, engineers and other professionals in the energy services industry, could have a material adverse effect on our business, financial condition, results of operations and our ability to successfully or timely execute our business plan.

If our intended expansion of our business is not successful, our financial condition, profitability and results of operations could be adversely affected, and we may not achieve increases in revenue and profitability that we hope to realize.

A key element of our business strategy involves the expansion of our services, geographic presence and customer base. These aspects of our strategy are subject to numerous risks and uncertainties, including:

- an inability to retain or hire experienced crews and other personnel;
- a lack of customer demand for the services we intend to provide;
- an inability to secure necessary financing, equipment, raw materials (particularly sand and other proppants) or technology to successfully execute our expansion plans;
- shortages of water used in our sand processing operations and our hydraulic fracturing operations;
- unanticipated delays that could limit or defer the provision of services by us and jeopardize our relationships with existing customers and adversely affect our ability to obtain new customers for such services; and
- competition from new and existing services providers.

Encountering any of these or any unforeseen problems in implementing our planned expansion could have a material adverse impact on our business, financial condition, results of operations and cash flows, and could prevent us from achieving the increases in revenues and profitability that we hope to realize.

Our liquidity needs could restrict our operations and make us more vulnerable to adverse economic conditions.

Our indebtedness may adversely affect our operations and limit our growth, and we may have difficulty making debt service payments on such indebtedness as payments become due. Our level of indebtedness may affect our operations in several ways, including the following:

- increasing our vulnerability to general adverse economic and industry conditions;
- the covenants that are contained in the agreements governing our indebtedness could limit our ability to borrow funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants could also affect our flexibility in planning for, and reacting to, changes in the economy and in our industries;
- any failure to comply with the financial or other covenants of our debt, including covenants that impose requirements to maintain certain financial ratios, could result in an event of default, which could result in some or all of our indebtedness becoming immediately due and payable;
- our level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other general corporate purposes; and
- our business may not generate sufficient cash flow from operations to enable us to meet our obligations under our indebtedness.

Our revolving credit facility provides, and any future credit facilities may provide, for fluctuating interest rates, which may increase or decrease our interest expense.

Our revolving credit facility provides for fluctuating interest rates, primarily based on the London interbank offered rate, or LIBOR, for deposits of U.S. dollars. LIBOR tends to fluctuate based on multiple facts, including general short-term interest rates, rates set by the U.S. Federal Reserve, which indicated plans for multiple interest rate increases in 2022, and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. At December 31, 2021, we had $83 million borrowings outstanding under our revolving credit facility and availability under our credit facility was approximately $17 million, after giving effect to $9 million of outstanding letters of credit and the requirement to maintain a $10 million reserve out of the available borrowing capacity during the limited waiver period. A 1% increase or decrease in the interest rate at that time would have increased or decreased our interest expense by approximately $1 million per year, based on $83 million outstanding and a weighted average interest rate of 4.17%. We have not hedged our interest rate exposure with respect to our floating rate debt. Accordingly, our interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. To the extent the interest rates applicable to our floating rate debt increase, our interest expense will increase, in which event we may have difficulties making interest payments and funding our other fixed costs, and our available cash flow may be adversely affected.

The U.K. Financial Conduct Authority (the authority that regulates LIBOR), which we refer to as FCA, has announced that it intends to stop one week and two month U.S. Dollar LIBOR rates after 2021. On March 5, 2021, the ICE Benchmark Administration, which administers LIBOR, and the FCA announced that all LIBOR settings will either cease to be provided by any administrator, or no longer be representative immediately after 2021, for all non-U.S. dollar LIBOR settings and one-week and two-month U.S. dollar LIBOR settings, and immediately after June 30, 2023 for the remaining U.S. dollar LIBOR settings. In light of these recent announcements, the future of LIBOR at this time is uncertain and any changes in the methods by which LIBOR is determined or regulatory activity related to LIBOR's phase-out could cause LIBOR to perform differently than in the past or cease to exist. Our current credit agreement provides for any changes away from LIBOR to a successor rate to be based on prevailing or equivalent standards, however, changes in the method of calculating LIBOR, or the discontinuation, reform or replacement of LIBOR or any other benchmark rates may adversely affect interest rates and result in higher borrowing costs. This could materially and adversely affect our results of operations, cash flow and liquidity.

We may not be able to provide services that meet the specific needs of oil and natural gas exploration and production companies or utilities at competitive prices.

The markets in which we operate are generally highly competitive and have relatively few barriers to entry. The principal competitive factors in our markets are price, product and service quality and availability, responsiveness, experience, technology, equipment quality and reputation for safety. We compete with large national and multi-national companies that have longer operating histories, greater financial, technical and other resources and greater name recognition than we do. Several of our competitors provide a broader array of services and have a stronger presence in more geographic markets. In addition, we compete with several smaller companies capable of competing effectively on a regional or local basis. Our competitors may be able to respond more quickly to new or emerging technologies and services and changes in customer requirements. Some contracts are awarded on a bid basis, which further increases competition based on price. Pricing is often the primary factor in determining which qualified contractor is awarded a job. The competitive environment may be further intensified by mergers and acquisitions among oil and natural gas or utility companies or other events that have the effect of reducing the number of available customers. As a result of competition, we may lose market share or be unable to maintain or increase prices for our present services or to acquire additional business opportunities, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, some exploration and production companies have begun performing hydraulic fracturing and directional drilling on their wells using their own equipment and personnel. Any increase in the development and utilization of in-house fracturing and directional drilling capabilities by our customers could decrease the demand for our oil and natural gas services and have a material adverse impact on our business.

Our operations are subject to hazards inherent in the oil and natural gas and energy infrastructure industries, which could expose us to substantial liability and cause us to lose customers and substantial revenue.

Our operations include hazards inherent in the oil and natural gas and energy infrastructure industries, such as equipment defects, vehicle accidents, fires, explosions, blowouts, surface cratering, uncontrollable flows of gas or well fluids, pipe or pipeline failures, abnormally pressured formations and various environmental hazards such as oil spills and releases of, and exposure to, hazardous substances. For example, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations. The cost of managing such risks may be significant. The frequency and severity of such incidents will affect operating costs, insurability and relationships with customers, employees and regulators. In particular, our customers may elect not to purchase our services if they view our environmental or safety record as unacceptable, which could cause us to lose customers and substantial revenues. In addition, these risks may be greater for us than some of our competitors because we sometimes acquire companies that may not have allocated significant resources and management focus to safety and environmental matters and may have a poor environmental and safety record and associated possible exposure. Our insurance may not be adequate to cover all losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations and cash flows. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and the insurance coverage may not be adequate to cover claims that may arise, or we may not be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We are subject to extensive environmental, health and safety laws and regulations that may subject us to substantial liability or require us to take actions that will adversely affect our results of operations.

Our business is significantly affected by stringent and complex federal, state and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection and health and safety matters. As part of our business, we handle, transport and dispose of a variety of fluids and substances, including hydraulic fracturing fluids which can contain hydrochloric acid and certain petrochemicals. This activity poses some risks of environmental liability, including leakage of hazardous substances from the wells to surface and subsurface soils, surface water or groundwater. We also handle, transport and store these substances. The handling, transportation, storage and disposal of these fluids are regulated by a number of laws, including: the Resource Conservation and Recovery Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Water Act; the Safe Drinking Water Act; and other federal and state laws and regulations promulgated thereunder. The cost of compliance with these laws can be significant. Failure to properly handle, transport or dispose of these materials or otherwise conduct our operations in accordance with these and other environmental laws could expose us to substantial liability for administrative, civil and criminal penalties, cleanup and site restoration costs and liability associated with releases of such materials, damages to natural resources and other damages, as well as potentially impair our ability to conduct our operations. We could be exposed to liability for cleanup costs, natural resource damages and other damages under these and other environmental laws. Such liability is commonly on a strict, joint and several liability basis, without regard to fault. Liability may be imposed as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior operators or other third parties. Environmental laws and regulations have changed in the past, and they are likely to change in the future. If existing environmental requirements or enforcement policies change and become more stringent, we may be required to make significant unanticipated capital and operating expenditures. For a detailed description of environmental laws and regulations applicable to us and their impact on our operations, see "Item 1. Business—Regulations" above.

Further, in connection with providing our infrastructure services, we have made a substantial investment in construction equipment that utilizes petroleum-based fuel. Any changes in laws requiring us to use equipment that runs on alternative fuels could require a significant investment, which could have a material adverse effect on our results of operations, cash flows and liquidity.

Changes in environmental laws could increase costs and harm our business, financial condition and results of operations.

President Biden has issued several executive orders promoting various programs and initiatives designed to, among other things, curtail climate change, control the release of methane from new and existing oil and gas operations, and pause new oil and gas leasing on public lands. It remains unclear what additional actions President Biden will take and what support he will have for any potential legislative changes from Congress. Further, it is uncertain to what extent any new environmental laws or regulations, or any repeal of existing environmental laws or regulations, may affect our oilfield services operations. However, such actions could materially increase our costs or impair our ability to explore and develop other projects, which could materially harm our business, financial condition and results of operations.

Our operations in our natural sand proppant services business are dependent on our rights and ability to mine our properties and on our having renewed or received the required permits and approvals from governmental authorities and other third parties.

We hold numerous governmental, environmental, mining and other permits, water rights and approvals authorizing operations at our production facilities. For our extraction and processing in Wisconsin, the permitting process is subject to federal, state and local authority. For example, at the federal level, a Mine Identification Request must be filed and obtained before mining commences. If wetlands are implicated, a U.S. Army Corps of Engineers Wetland Permit is required. At the state level, a series of permits are required related to air quality, wetlands, water quality (waste water and storm water), grading, endangered species and archaeological assessments in addition to other permits depending upon site specific factors and operational detail. At the local level, zoning, building, storm water, erosion control, wellhead protection, road usage and access are all regulated and require permitting to some degree. A non-metallic mining reclamation permit is required. A decision by a governmental agency or other third party to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on our ability to continue operations.

Title to, and the area of, mineral properties and water rights may also be disputed. Mineral properties sometimes contain claims or transfer histories that examiners cannot verify. A successful claim that we do not have title to our property or lack appropriate water rights could cause us to lose any rights to explore, develop and extract minerals, without compensation for our prior expenditures relating to such property. Our business may suffer a material adverse effect in the event we have title deficiencies.

In some instances, we have received access rights or easements from third parties, which allow for a more efficient operation than would exist without the access or easement. A third party could take action to suspend the access or easement, and any such action could be materially adverse to our business, results of operations, cash flows or financial condition.

Penalties, fines or sanctions that may be imposed by the U.S. Mine Safety and Health Administration could have a material adverse effect on our proppant production and sales business and our overall financial condition, results of operations and cash flows.

The U.S. Mine Safety and Health Administration, or MSHA, has primary regulatory jurisdiction over commercial silica operations, including quarries, surface mines, underground mines, and industrial mineral process facilities. In addition, MSHA representatives perform at least two annual inspections of our production facilities to ensure employee and general site safety. As a result of these and future inspections and alleged violations and potential violations, we and our suppliers could be subject to material fines, penalties or sanctions. Any of our production facilities or our suppliers' mines could be subject to a temporary or extended shut down as a result of an alleged MSHA violation. Any such penalties, fines or sanctions could have a material adverse effect on our proppant production and sales business and our overall financial condition, results of operations and cash flows.

Increasing trucking regulations may increase our costs and negatively impact our results of operations.

In connection with our business operations, including the transportation and relocation of our energy service equipment, shipment of frac sand and general freight hauling, we operate trucks and other heavy equipment. As such, we operate as a motor carrier in providing certain of our services and therefore are subject to regulation by the United States Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations, driver licensing, insurance requirements, financial reporting and review of certain mergers, consolidations and acquisitions, and transportation of hazardous materials (HAZMAT). Our trucking operations are subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive or work in any specific period, onboard black box recorder device requirements or limits on vehicle weight and size. Interstate motor carrier operations are subject to safety requirements prescribed by the United States Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Matters such as the weight and dimensions of equipment are also subject to federal and state regulations. From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Certain motor vehicle operators require registration with the Department of Transportation. This registration requires an acceptable operating record. The Department of Transportation periodically conducts compliance reviews and may revoke registration privileges based on certain safety performance criteria that could result in a suspension of operations.

Conservation measures and technological advances could reduce demand for oil and natural gas and our services.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas, resulting in reduced demand for oilfield services. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Changes in tax laws and regulations or adverse outcomes resulting from examination of our tax returns may adversely affect our business, results of operations, financial condition and cash flow.

We are subject to tax liabilities imposed by multiple jurisdictions, including income taxes, indirect taxes (excise/duty, sales/use and value-added taxes), payroll taxes, franchise taxes, withholding taxes and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted or proposed that could result in increased expenditures for tax liabilities in the future, which could have a material adverse effect on our results of operations, financial condition and cash flows. Additionally, many of these liabilities are subject to periodic audits by the respective taxing authority. Subsequent changes to our tax liabilities as a result of these audits may subject us to interest and penalties.

Our income tax returns are subject to review and examination by the applicable tax authorities. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for income taxes. We do not recognize the benefit of income tax positions we believe are more likely than not to be disallowed upon challenge by a tax authority. Although we believe our tax provisions are adequate, the final determination of tax audits and any related disputes could be materially different from our historical income tax provisions and accruals. The results of audits or related disputes could have an adverse effect on our financial statements for the periods for which the applicable final determinations are made.

Losses and liabilities from uninsured or underinsured activities could have a material adverse effect on our financial condition and operations.

The operational insurance coverage we maintain for our business may not fully insure us against all risks, either because insurance is not available or because of the high premium costs relative to perceived risk. Further, any insurance obtained by us may not be adequate to cover any losses or liabilities and this insurance may not continue to be available at all or on terms which are acceptable to us. Insurance rates have in the past been subject to wide fluctuation and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on our business activities, financial condition and results of operations.

We may be subject to claims for personal injury and property damage, which could materially adversely affect our financial condition and results of operations.

We operate with most of our customers under master service agreements, or MSAs. We endeavor to allocate potential liabilities and risks between the parties in the MSAs. Generally, under our MSAs, including those relating to our hydraulic fracturing services, we assume responsibility for, including control and removal of, pollution or contamination which originates above surface and originates from our equipment or services. Our customer assumes responsibility for, including control and removal of, all other pollution or contamination which may occur during operations, including that which may result from seepage or any other uncontrolled flow of drilling fluids. We may have liability in such cases if we are negligent or commit willful acts. Generally, our customers also agree to indemnify us against claims arising from their employees' personal injury or death to the extent that, in the case of our hydraulic fracturing operations, their employees are injured or their properties are damaged by such operations, unless resulting from our gross negligence or willful misconduct. Similarly, we generally agree to indemnify our customers for liabilities arising from personal injury to or death of any of our employees, unless resulting from gross negligence or willful misconduct of the customer. In addition, our customers generally agree to indemnify us for loss or destruction of customer-owned property or equipment and in turn, we agree to indemnify our customers for loss or destruction of property or equipment we own. Losses due to catastrophic events, such as blowouts, are generally the responsibility of the customer. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into an MSA with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operation.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, whether due to cyberattack or otherwise, possible consequences include our loss of communication links and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The energy services industry has become increasingly dependent on digital technologies to conduct certain processing activities. For example, we depend on digital technologies to perform many of our services and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems and networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks.

Risks Inherent to Our Common Stock

Our largest stockholder controls a significant percentage of our common stock, and its interests may conflict with those of our other stockholders.

Wexford, through its affiliate MEH Sub LLC, beneficially own approximately 47.6% of our outstanding common stock. As a result, Wexford can exercise significant influence over matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. Further, individuals who serve as our directors are affiliates of Wexford. This concentration of ownership and relationship with Wexford makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. In addition, we have engaged, and expect to continue to engage, in related party transactions involving Wexford, and certain companies they control. The interests of Wexford with respect to matters potentially or actually involving or affecting us, such as services provided, future acquisitions, financings and other corporate opportunities, and attempts to acquire us, may conflict with the interests of our other stockholders. This concentrated ownership will make it impossible for another company to acquire us and for you to receive any related takeover premium for your shares unless these stockholders approve the acquisition.

A significant reduction by Wexford of its ownership interests in us could adversely affect us.

We believe that Wexford’s substantial ownership interest in us provides it with an economic incentive to assist us to be successful. Wexford is not subject to any obligation to maintain its ownership interest in us and may elect at any time to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If Wexford sells all or a substantial portion of its ownership interest in us, it may have less incentive to assist in our success and its affiliates that serve as members of our board of directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies which could adversely affect our cash flows or results of operations.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to continue comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price, results of operations and financial condition could be materially adversely affected.

As a smaller reporting company and an accelerated filer, we are required to document and test our internal control over financial reporting and issue management’s assessment of our internal control over financial reporting under Section 404 of the Sarbanes Act of 2002. As we perform the required testing of our internal control over financial reporting, we may identify areas requiring improvement, and we may have to design enhanced processes and controls to address issues identified through this review. We believe that the out-of-pocket costs, the diversion of management’s attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 of the Sarbanes-Oxley Act could be significant. If the time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected.

If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify material weaknesses in internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

The corporate opportunity provisions in our certificate of incorporation could enable Wexford or other affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our common stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. As described elsewhere in this report, including in the notes to our consolidated financial statements, these transactions include, among others, a joint venture, agreements to provide our services and frac sand products to our affiliates and agreements pursuant to which our affiliates provide or will provide us with certain services, including administrative and advisory services and office space. Each of these entities is either controlled by or affiliated with Wexford, as the case may be, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests because Wexford may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, see "*—Risks Inherent to Our Common Stock—Our largest stockholder controls a significant percentage of our common stock, and its interests may conflict with those of our other stockholders*."

If the price of our common stock fluctuates significantly, your investment could lose value.

Although our common stock is listed on The Nasdaq Global Select Market, an active public market for our common stock may not be maintained. If an active public market for our common stock is not maintained, the trading price and liquidity of our common stock will be materially and adversely affected. Without a large float, our common stock is less liquid than the securities of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. The market price for our common stock has fluctuated significantly, ranging from a high of $7.27 per share to a low of $1.73 per share during 2021. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. In addition, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including:

- our quarterly or annual operating results;
- changes in our earnings estimates;
- investment recommendations by securities analysts following our business or our industries;
- additions or departures of key personnel;
- changes in the business, earnings estimates or market perceptions of our competitors;
- our failure to achieve operating results consistent with securities analysts' projections;
- changes in industry, general market or economic conditions; and
- announcements of legislative or regulatory change.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industries. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce the price for our common stock.

Wexford beneficially owns a substantial amount of our common stock and may sell such common stock in the public or private markets. Sales of these shares of common stock or sales of substantial amounts of our common stock by other stockholders, or the perception that such sales may occur, could adversely affect the prevailing market price of our common stock.

As of December 31, 2021, Wexford beneficially owned 47.6% shares of our common stock, respectively. Sales of these shares of common stock or sales of substantial amounts of our common stock by other stockholders, or the perception that such sales may occur, could cause the price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely revise their recommendations regarding our stock or if our operating results do not meet their expectations, the price of our stock could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our stock or if our operating results do not meet their expectations, our stock price could decline.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders;
- limitations on the ability of our stockholders to call a special meeting and act by written consent;
- the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and
- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

Our certificate of incorporation designates courts in the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Our certificate of incorporation provides that, subject to limited exceptions, the Court of Chancery of the State of Delaware will be the sole and exclusive forum for:

- Any derivative action or proceeding brought on our behalf;
- Any action asserting a claim of breach of fiduciary duty owed by any of our directors, officers or other employees to us or our stockholders;
- Any action asserting a claim against us arising pursuant to any provision of the Delaware General Corporation Law; or
- Any other action asserting a claim against us that is governed by the internal affairs doctrine.

In addition, our certificate of incorporation provides that if any action specified above (each is referred to herein as a covered proceeding), is filed in a court other than the specified Delaware courts without the approval of our board of directors (each is referred to herein as a foreign action), the claiming party will be deemed to have consented to (i) the personal jurisdiction of the specified Delaware courts in connection with any action brought in any such courts to enforce the exclusive forum provision described above and (ii) having service of process made upon such claiming party in any such enforcement action by service upon such claiming party's counsel in the foreign action as agent for such claiming party. These provisions may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and our directors, officers and employees. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the covered proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business and financial condition.

The declaration of dividends on our common stock is within the discretion of our board of directors based upon a review of relevant considerations, and there is no guarantee that we will pay any dividends in the future or at levels anticipated by our stockholders.

On July 16, 2018, our board of directors initiated a quarterly dividend policy on shares of our common stock payable quarterly beginning with the second quarter of 2018. In July 2019, as a result of oilfield market conditions and other factors, which included the status of collections from PREPA, our board of directors suspended the quarterly cash dividend. The decision to pay dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, or declare dividends at rates that are less than anticipated, either of which could reduce returns to our stockholders.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

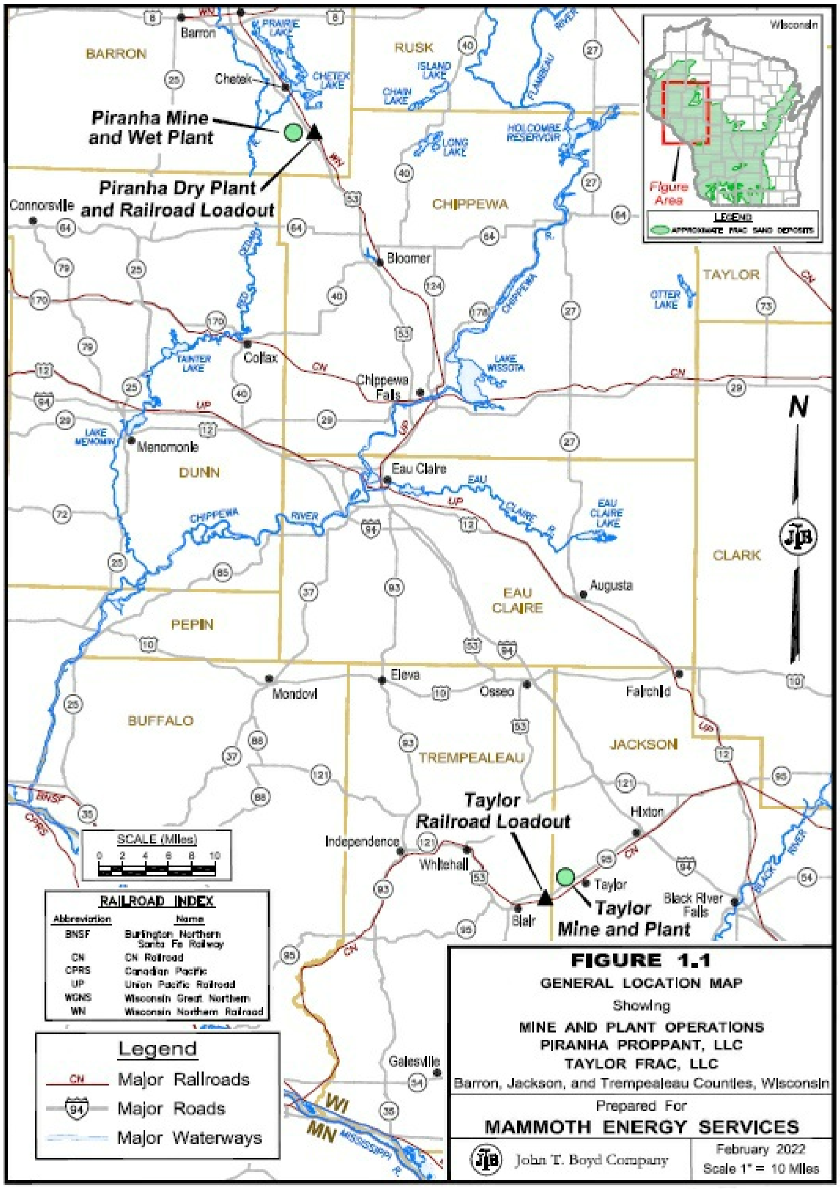
Overview of Sand Properties and Operations

Information concerning our mining properties in this annual report has been prepared in accordance with the requirements of subpart 1300 of Regulation S-K, which first became applicable to us for the fiscal year ended December 31, 2021. These requirements differ significantly from the previously applicable disclosure requirements of SEC Industry Guide 7. Among other differences, subpart 1300 of Regulation S-K requires us to disclose our mineral resources, in addition to our mineral reserves, as of the end of our most recently completed fiscal year both in the aggregate and for each of our individually material mining properties.

As used in this annual report, the terms “mineral resource,” “measured mineral resource,” “indicated mineral resource,” “inferred mineral resource,” “mineral reserve,” “proven mineral reserve” and “probable mineral reserve” are defined and used in accordance with subpart 1300 of Regulation S-K. Under subpart 1300 of Regulation S-K, mineral resources may not be classified as “mineral reserves” unless the determination has been made by a qualified person that the mineral resources can be the basis of an economically viable project. You are specifically cautioned not to assume that any part or all of the mineral deposits (including any mineral resources) in these categories will ever be converted into mineral reserves, as defined by the SEC. You are further cautioned that, except for that portion of mineral resources classified as mineral reserves, mineral resources do not have demonstrated economic value.

The information that follows is derived, in part, from the technical report summary prepared by John T. Boyd Company, our third party mining and geological consultant and an external qualified person, (“John T. Boyd”), in compliance with Item 601(b)(96) and subpart 1300 of Regulation S-K. 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, filed as Exhibit 96.1 hereto, incorporated herein by reference and made a part of this annual report.

Our natural sand proppant business mines, processes and sells high quality Northern White silica, a key input for the hydraulic fracturing of oil and gas wells, which we refer to as frac sand. Northern White frac sand deposits are generally located in the north-central portion of the United States (predominantly in Minnesota, Wisconsin and Illinois, with lesser amounts in Arkansas and Iowa). Northern White frac sand is found in poorly cemented Cambrian and Ordovician sandstones and in unconsolidated alluvial deposits locally derived from these sandstones. All of our frac sand facilities are located in Wisconsin, with our Taylor facilities located in Jackson County, our Piranha facilities located in Barron County and our Muskie facilities located in Pierce County.



Our frac sand facilities consist of three dry plants with a total permitted capacity of 5.7 million tons of sand per year, and two wet plants, with a total permitted capacity of 8.7 million tons of sand per year, that supply two of the dry plants with Northern White silica sand, which we believe is some of the highest quality raw frac sand available. Our Muskie plant in Pierce County, Wisconsin is currently idled. Our frac sand facilities operate seasonally from March or April through October or November depending on both weather and material demand.

We produce predominantly 20/40-mesh, 30/50-mesh and 40/70-mesh frac sand. The production of our frac sand consists of three basic processes: mining, wet plant operations and dry plant operations. All mining activities take place in an open pit environment, whereby we remove the topsoil, which is set aside, and then remove other non-economic minerals, or “overburden,” to expose the sand deposits. A third-party contractor then “bumps” the sand using explosives on the mine face, which causes the sand to fall into the pit, where it is then carried by truck or conveyor to the wet plant operations. At our wet plants, the mined sand goes through a series of processes designed to separate the sand from unusable materials. The resulting wet sand is then conveyed to a wet sand stockpile where most of the water is allowed to drain into our on-site recycling facility, while the remaining fine grains and materials, if any, are separated through a series of settlement ponds. We reuse the water that does not evaporate in our wet process. Wet sand from our stockpile is then conveyed or trucked to our dry plants where the sand is dried, screened into specific mesh categories and stored in silos. From the silos, we load sand directly into railcars or trucks, which we then ship to one of our transloading facilities or directly to our customers. For information regarding our transloading facilities and shipping capabilities, see "Item 1. Business-Our Services-Natural Sand Proppant Services."

Our Wisconsin dry plants are enclosed facilities capable of running year-round, regardless of the weather. Under normal market conditions, we typically operate our plants with work crews of ten to 15 employees. These crews typically work 40-hour weeks, with shifts between eight and twelve hours, depending on the employee's function. Because raw sand cannot be wet-processed during extremely cold temperatures, we typically mine and wet-process sand eight months out of the year at our Taylor and Piranha locations. Our Muskie location has an indoor wash facility, which is capable of being run year-round.

Our Taylor and Piranha mines are located in western Wisconsin, near an estimated combined population of over 350,000 people. Both sites are accessible via a well-developed network of primary and secondary roads, which offer direct access to the mines and processing facilities and are open year-round. Our Taylor facilities have access to the Canadian National rail network, while our Piranha facilities have access to the Union Pacific rail network. Both operations have readily available access to requisite electrical power, natural gas and water. Each of our facilities undergoes regular maintenance to minimize unscheduled downtime and to ensure that the quality of our frac sand meets API standards and our customers' specifications. In addition, we make capital investments in our facilities as required to support customer demand, and our performance goals.

The following table provides information regarding our aggregate sand mined for December 31, 2021, 2020 and 2019:

	Total Sand Mined (Thousands of Tons)		
	As of December 31,		
	2021	**2020**	**2019**
Plant Location			
Taylor in Jackson County, Wisconsin	567	589	1,649
Piranha in Barron County, Wisconsin	320	—	2,099
Muskie in Pierce County, Wisconsin	—	—	—
Total	887	589	3,748

Mineral Resources and Reserves

The quantity and nature of our mineral resources and reserves are estimated by John T. Boyd, while we internally track depletion rate on an interim basis. Estimates of frac sand reserves for the Taylor mine and Piranha mine were derived contemporaneously with estimates of frac sand resources. To derive an estimate of saleable product tons (proven and probable frac sand reserves), the following modifying factors were applied to the in-place measured and indicated frac sand resources underlying the respective mine plan areas:

- A 90% mining recovery factor, which assumes that 10% of the mineable (in-place) frac sand resource will not be recovered during mining for various reasons. Applying this recovery factor to the in-place resource results in the estimated sand tonnage that will be delivered to the wet process plant.
- An overall 79% processing recovery. This recovery factor accounts for losses in the wet and dry plants. This recovery factor accounts for removal of out-sized (i.e., larger than 20-mesh and smaller than 100-mesh) sand and losses in the wet and dry processing plants due to minor inefficiencies.

We do not have any reportable frac sand resources excluding those converted to frac sand proven reserves for the Taylor and Piranha mines. Any frac sand within the defined boundaries of the Taylor and Piranha mines which is not reported as frac sand reserves are not considered to have potential economic viability. Therefore, they are not reportable as frac sand resources. Further, as we do not own any mineral rights for the Muskie properties, but, rather, own only the surface rights to the processing plants, we do not (and do not expect to ever) report any reserves attributable to our Muskie property. John T. Boyd updates our reserve estimates annually, making necessary adjustments for operations at each location during the year and additions or surveying, drill core analysis and other tests to confirm the quantity and quality of the reserves. The following table presents our estimated frac sand reserves by product mesh size for the Taylor and Piranha mines as of December 31, 2021:

		Estimated Proven Reserves[(1)(2)] at December 31, 2021			
		Amount (Thousands of Tons)			
Mine	**Reserves Category**	**20/40 Mesh**	**40/70 Mesh**	**70/140 Mesh**	**Total**
Taylor	Proven	6,109	11,801	6,367	24,277
Piranha	Proven	11,414	20,333	6,067	37,814
Total		17,523	32,134	12,434	62,091

1. Pricing data based on the weighted average projected sales price for sand of $19.04 per ton for Taylor's operations and $18.06 for Piranha's operations.
2. John T. Boyd has determined that all reportable mineral resources for the Taylor and Piranha mines are categorized as proven reserves as the areas are well explored and exhibit acceptable drill hole data spacing to be classified as measured resources.

We categorize our sand properties in accordance with the SEC definition in Item 1300 of Regulation S-K. Our mineral resources are concentration or occurrence of material of economic interest in or on the Earth's crust in such form, grade or quality and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled. Our sand reserves are our estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, they are 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.

John T. Boyd updates our reserve estimates annually, making necessary adjustments for operations at each location during the year and additions or surveying, drill core analysis and other tests to confirm the quantity and quality of the reserves. To opine as to the economic viability of our reserves, John T. Boyd reviewed our financial cost and revenue per ton data at the time of the proven reserve determination. Our 2021 average monthly sales prices ranged from approximately $14 to $19 per ton free on board mine. Based on its review of our cost structure and its extensive experience with similar operations, John T. Boyd concluded that it is reasonable to assume that we will operate under a similar cost structure over the remaining life of our reserves. Based on these assumptions, and taking into account possible cost increases associated with a maturing mine, John T. Boyd concluded that our current operating margins are sufficient to expect continued profitability throughout the life of our reserves.

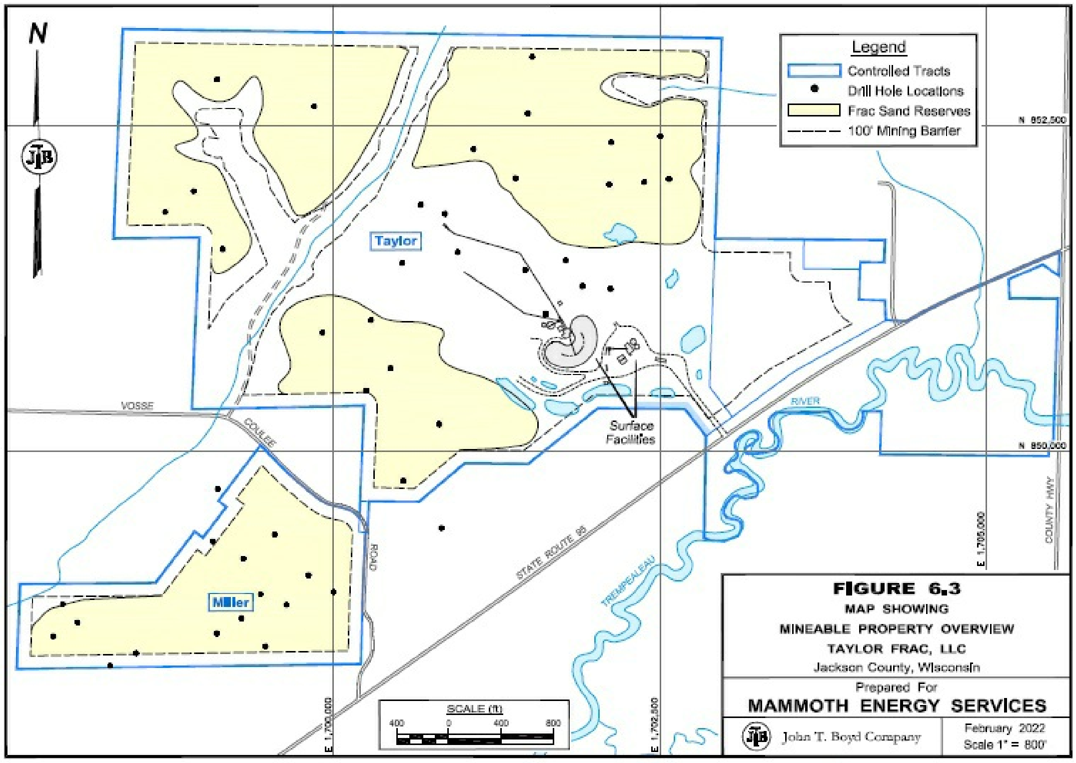
Our proppant sand reserves consist of Northern White silica sand, giving us access to a range of high-quality sand grades meeting or exceeding all API specifications, including a mix between concentrations of coarse grades (20/40 and 30/50 mesh sands) and finer grades (40/70 and 100 mesh). Our sample boring data and our historical production data have indicated that our reserves contain deposits of approximately 40% 40 mesh or coarser substrate. The coarseness and conductivity of Northern White frac sand significantly enhances recovery of oil and liquids-rich gas by allowing hydrocarbons to flow more freely than is sometimes possible with native sand. The low acid-solubility increases the integrity of Northern White frac sand relative to other proppants with higher acid-solubility, especially in shales where hydrogen sulfide and other acidic chemicals are co-mingled with the targeted hydrocarbons. In addition, its crush resistant properties enable Northern White frac sand to be used in deeper drilling applications than the frac sand produced from many native mineral deposits. We believe that the coarseness, conductivity, sphericity, acid-solubility and crush-resistant properties of our Northern White sand reserves and our facilities' connectivity to rail and other transportation infrastructure afford us an advantage over our competitors and make us one of a select group of sand producers capable of delivering high volumes of frac sand that is optimal for oil and natural gas production to all major unconventional resource basins currently producing throughout North America.

Surface and Mineral Rights

For each of our Taylor and Piranha frac sand facilities, we own surface and mineral rights. For our Muskie sand facility, we own surface rights.

Individual Properties

Taylor. Our Taylor operation is located less than one mile northwest of the town of Taylor, in Jackson County, Wisconsin and encompasses a total of approximately 393 acres. Approximately 148 acres of frac sand resources remain on this property. We own in fee numerous land parcels which comprise the processing plant site, mineral resource areas and rail loadout facility. Our rail loadout facility, located in Trempealeau County, Wisconsin, is approximately two miles southwest of the mine and processing facility. Our Taylor operation commenced mining operations in 2012. We acquired the Taylor operation in June 2017 when we acquired Sturgeon Acquisitions, LLC. The total net book value of the Taylor operation's real property and fixed assets as of December 31, 2021, was $28.2 million.



The site contains a mine with 24.7 million tons of proven recoverable proppant sand reserves as of December 31, 2021, based on estimates prepared by John T. Boyd. Our Taylor wet plant can currently process up to 2.6 million tons of wet frac sand per year. Our Taylor dry plant is adjacent to our Taylor wet plant and wash facilities. As of December 31, 2021, the dry plant had a rated production capacity of 2.2 million tons per year. Our current air permit allows us to produce up to 2.2 million tons per year of finished product. The Taylor facility includes a 150 ton per hour natural gas fluid bed dryer and a 100 ton per hour natural gas fluid bed dryer as well as nine high capacity screeners that are capable of producing 2.2 million tons of frac sand per year. During the year ended December 31, 2021, our Taylor facility produced 0.4 million tons of finished sand product. Our finished product is transported via truck to our transloading facility with rail access.

We estimate an overall product yield (after mining and processing losses) of approximately 66% for the Taylor mine. John T. Boyd utilized post December 31, 2017 production data we provided, along with the John T. Boyd January 2019 Report amending the resource tons as of December 31, 2017, to reconcile the amended estimate from the December 31, 2017 estimate to December 31, 2021. The following table presents a summary of our mineral reserves for the Taylor mine as of December 31, 2021, together with a comparison to the reserves as of the end of the preceding fiscal year and an explanation of any material changes.

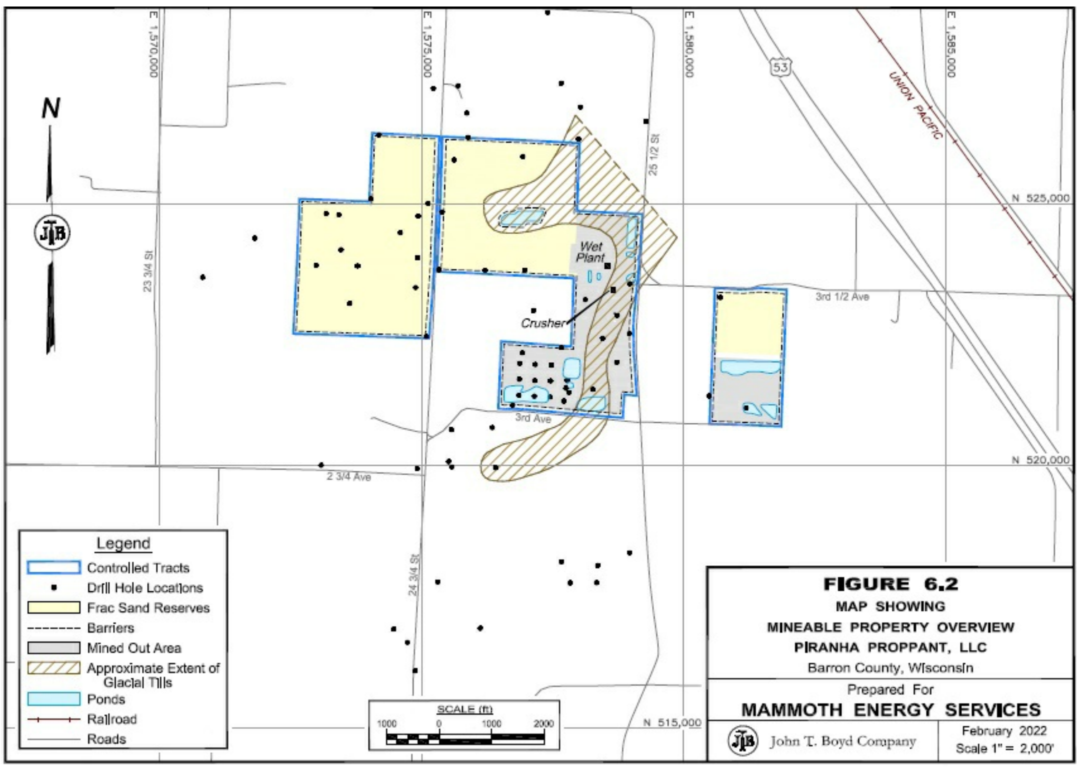
Taylor Mine – Summary of Reserves(1)(2) (Thousands of Tons)

	Amount as of			
Reserves Category	**December 31, 2021**	**December 31, 2020**	**Change**	**% Change**
Proven	24,277	24,691	(414)	(2) %

1. Pricing data based on the weighted average projected sales price for sand of $19.04 per ton.
2. John T. Boyd has determined that all reportable mineral resources for the Taylor mine are categorized as proven reserves as the area is well explored and exhibit acceptable drill hole data spacing to be classified as a measured resource.

The decrease from 2020 to 2021 is primarily attributed to depletion by mining 0.6 million tons of sand.

Piranha. Our Piranha operation is located approximately five miles northwest of the town of New Auburn, in Baron County, Wisconsin and encompasses a total of approximately 608 acres. The current estimated mineable area is approximately 313 acres, or 52% of the total property, after observing setbacks, right of ways, processing areas and other non-mining acreage. We own 100% of the surface and mineral rights. Our dry plant and loadout is also located in Baron County and is approximately one mile east of the mine and wet processing facility. We acquired the Piranha operation on May 26, 2017 from Chieftain Sand and Proppant LLC (Chieftain). Under Chieftain, the property commenced mining operations in August 2012. In January 2018, we purchased the Conoboy tract, which is adjacent to a tract of land previously mined by Chieftain. The total net book value of the Piranha operation's real property and fixed assets as of December 31, 2021 was $16.8 million.



The site contains 38.1 million tons of proven recoverable proppant sand reserves as of December 31, 2021, based on estimates prepared by John T. Boyd. Our Piranha wet plant, which is adjacent to the mine, can process up to 4.7 million tons of wet sand per year and is located two miles from our Piranha dry plant, to which we have year-round trucking access. As of December 31, 2021, the dry plant facility had a rated production capacity of 2.6 million tons per year. Our current air permit allows us to produce up to 3.5 million tons per year of finished product. Our Piranha facility includes a 150 ton per hour natural gas fired fluid bed dryer and a 200 ton per hour natural gas fluid bed dryer as well as seven high capacity screeners capable of producing 2.6 million tons of frac sand per year. During the year ended December 31, 2021, our Piranha facility produced 0.5 million tons of sand. Our finished product is loaded directly into railcars. Our Piranha facility is capable of storing up to 400 railcars.

We estimate an overall product yield (after mining and processing losses) of approximately 71% for the Piranha mine. John T. Boyd utilized post March 31, 2017 production data we provided, in conjunction with other data, to reconcile the estimate from the March 31, 2017 volumetric estimate to December 31, 2021. The following table presents a summary of our mineral reserves for the Piranha mine as of December 31, 2021, together with a comparison to the reserves as of the end of the preceding fiscal year and an explanation of any material changes.

Piranha Mine – Summary of Reserves(1)(2) (Thousands of Tons)

	Amount as of			
Reserves Category	**December 31, 2021**	**December 31, 2020**	**Change**	**% Change**
Proven	37,814	38,050	(236)	(1) %

1. Pricing data based on the weighted average projected sales price for sand of $18.06 per ton.
2. John T. Boyd has determined that all reportable mineral resources for the Piranha mine are categorized as proven reserves as the area is well explored and exhibit acceptable drill hole data spacing to be classified as a measured resource.

The decrease from 2020 to 2021 is primarily attributed to depletion by mining 0.3 million tons of sand.

Muskie. Our Muskie facilities are located in Plum City, Wisconsin and encompass a total of approximately 40 acres. Although this plant is currently idled, our Muskie wet plant can process up to 1.3 million tons of wet sand per year. The site includes an indoor facility capable of washing sand year-round and an enclosed dry plant facility that has a rated production capacity of 2,400 tons per day. Our current air permit allows us to produce up to 0.9 million tons per year of finished product. The facility has a 100 ton per hour natural gas fired fluid bed dryer as well as six high capacity screeners that are capable of producing 0.9 million tons per year. As a result of adverse market conditions, production at our Muskie facility has been temporarily idled since September 2018. When operating, our finished product is transported via truck to a third-party facility with rail access. The site does not contain any proppant sand reserves. Our Muskie facility commenced operations in 2012. Muskie was contributed to Mammoth in November 2014. The total net book value of the Muskie operation's real property and fixed assets as of December 31, 2021, was $6.6 million.

Headquarters

Our corporate headquarters are located at 14201 Caliber Drive, Suite 300, Oklahoma City, Oklahoma 73134. We currently own 15 properties, five located in Texas, four located in Wisconsin, four located in Ohio and two located in Oklahoma, which are used for field offices, yards, production plants or housing. In addition to our headquarters, we also lease 30 properties that are used for field offices, yards or transloading facilities for frac sand. We believe that our facilities are adequate for our current operations.

Item 3. Legal Proceedings

We are a party to, or the subject of, certain investigations and legal proceedings discussed elsewhere in this annual report. For a description of such investigations and legal proceedings, see Note 19. Commitments and Contingencies to our consolidated financial statements included elsewhere in this annual report and Item 1A. "Risk Factors—Risks Related to Our Business and the Industries We Serve—*Cobra, one of our infrastructure services subsidiaries, was party to service contracts with PREPA. PREPA is currently subject to bankruptcy proceedings and, as a result, PREPA's ability to meet its payment obligations under the contracts is largely dependent upon funding from the FEMA or other sources. In the event that PREPA fails to pay amounts owed to us for services performed, our financial condition, results of operations and cash flows would be materially and adversely affected*." and "*—The outcomes of investigations and litigation relating to our contracts with PREPA may have a material adverse effect on our financial condition, results of operations and cash flows*."

In addition, due to the nature of our business, we are, from time to time, also involved in routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes.

Except as described elsewhere in this annual report, in the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our business, financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Our operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. Our failure to comply with such standards, or changes in such standards or the interpretation or enforcement thereof, could have a material adverse effect on our business and financial condition or otherwise impose significant restrictions on our ability to conduct mineral extraction and processing operations. Following passage of The Mine Improvement and New Emergency Response Act of 2006, MSHA significantly increased the numbers of citations and orders charged against mining operations. The dollar penalties assessed for citations issued has also increased in recent years. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Report.

PART II. OTHER INFORMATION

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information and Holders of Record

Our common stock is traded on the Nasdaq Global Select Market under the symbol "TUSK." As of the close of business on March 2, 2022, there were 53 holders of record of our common stock. The number of holders of record of our common stock is not representative of the number of beneficial holders because many of the shares are held by depositories, brokers or nominees. As of January 14, 2022, there were 5,213 beneficial holders of record of our common stock.

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

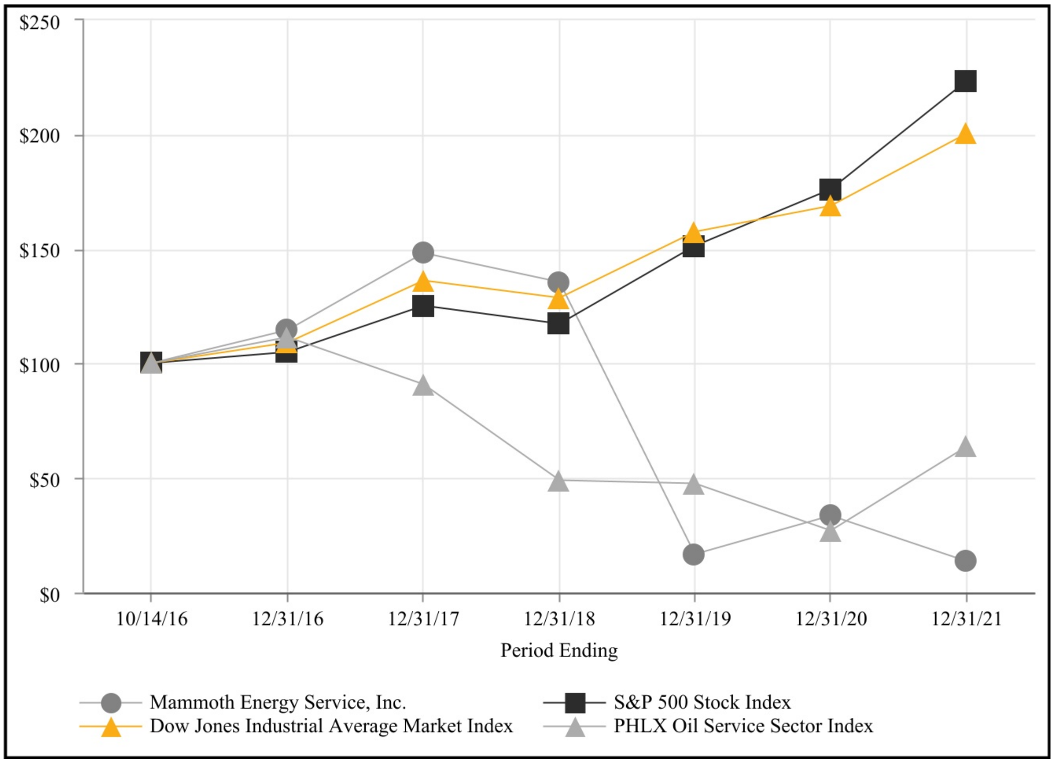
Dividends

On July 16, 2018, we initiated a quarterly dividend policy and declared our first quarterly cash dividend. In July 2019, as a result of oilfield market conditions and other factors, which included the status of collections from PREPA, our board of directors suspended the quarterly cash dividend.

Our board of directors' determination with respect to any future dividends will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, or declare dividends at rates that are less than currently anticipated.

Performance Graph

The following graph and table compares the cumulative total return of a $100 investment in our common stock from October 14, 2016, the date on which our stock began trading on the Nasdaq Global Select Market, through December 31, 2021, with the total cumulative return of a $100 investment in the Standard & Poors 500 Stock Index, the Dow Jones Industrial Average Market Index and the PHLX Oil Service Sector Index during that period.



	October 14, 2016	December 31, 2016	December 31, 2017	December 31, 2018	December 31, 2019	December 31, 2020	December 31, 2021
Mammoth Energy Service, Inc.	$ 100.00	$ 114.63	$ 148.04	$ 135.60	$ 16.59	$ 33.56	$ 13.73
S&P 500 Stock Index	$ 100.00	$ 104.88	$ 125.25	$ 117.44	$ 151.35	$ 175.96	$ 223.28
Dow Jones Industrial Average Market Index	$ 100.00	$ 108.96	$ 136.28	$ 128.61	$ 157.34	$ 168.74	$ 200.34
PHLX Oil Service Sector Index	$ 100.00	$ 111.51	$ 90.74	$ 48.90	$ 47.50	$ 26.90	$ 31.99

This graph shall not be deemed to be “soliciting material” or to be “filed” with the SEC.

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in Item 1A. "Risk Factors" and the section entitled "Forward-Looking Statements" appearing elsewhere in this annual report.

Overview

We are an integrated, growth-oriented energy services company focused on the construction and repair of the electric grid for private utilities, public investor-owned utilities and co-operative utilities through its infrastructure services businesses. We also provide products and services to enable the exploration and development of North American onshore unconventional oil and natural gas reserves. Our primary business objective is to grow our operations and create value for stockholders through organic growth opportunities and accretive acquisitions. Our suite of services includes infrastructure services, well completion services, natural sand proppant services, drilling services and other services. Our infrastructure services division provides engineering, design, construction, upgrade, maintenance and repair services to the electrical infrastructure industry. Our well completion services division provides hydraulic fracturing, sand hauling and water transfer services. Our natural sand proppant services division mines, processes and sells natural sand proppant used for hydraulic fracturing. Our drilling services division currently provides rental equipment, such as mud motors and operational tools, for both vertical and horizontal drilling. In addition to these service divisions, we also provide aviation services, equipment rentals, crude oil hauling services, remote accommodations and equipment manufacturing. We believe that the services we offer play a critical role in maintaining and improving electrical infrastructure as well as in increasing the ultimate recovery and present value of production streams from unconventional resources. Our complementary suite of services provides us with the opportunity to cross-sell our services and expand our customer base and geographic positioning.

Our transformation towards an industrial based company is ongoing. We offer infrastructure engineering services focused on the transmission and distribution industry and also have equipment manufacturing operations and offer fiber optic services. Our equipment manufacturing operations provide us with the ability to repair much of our existing equipment in-house, as well as the option to manufacture certain new equipment we may need in the future. The equipment manufacturing operations have initially served the internal needs for our water transfer, equipment rental and infrastructure businesses, but we expect to expand into third party sales in the future. Our fiber optic services include the installation of both aerial and buried fiber. We are continuing to explore other opportunities to expand our business lines as we shift to a broader industrial focus.

Our revenues, operating (loss) income and identifiable assets are primarily attributable to four reportable segments: infrastructure services; well completion services; natural sand proppant services; and drilling services. Since the dates presented below, we have conducted our operations through the following entities:

Infrastructure Services Segment

- Cobra Acquisitions LLC, or Cobra—January 2017
- Lion Power Services LLC, formerly Cobra Energy LLC—January 2017
- Higher Power Electrical LLC—April 2017
- 5 Star Electric LLC—July 2017
- Python Equipment LLC—December 2018
- Aquawolf LLC—September 2019
- Falcon Fiber Solutions LLC—May 2021

Well Completion Services Segment

- Stingray Pressure Pumping LLC—March 2012
- Silverback Energy LLC—November 2012
- Redback Pump Down Services LLC—January 2015
- Mr. Inspections LLC—January 2015
- Mammoth Equipment Leasing LLC—November 2016
- Bison Sand Logistics LLC—January 2018
- Aquahawk Energy LLC—June 2018

Natural Sand Proppant Services Segment

- Muskie Proppant LLC—September 2011

- Barracuda Logistics LLC—October 2014
- Piranha Proppant LLC—May 2017
- Sturgeon Acquisitions LLC—June 2017
- Taylor Frac, LLC—June 2017
- Taylor Real Estate Investments, LLC—June 2017
- South River Road, LLC—June 2017

Drilling Services Segment

- Bison Drilling and Field Services, LLC—November 2010
- Panther Drilling Systems LLC—December 2012
- Bison Trucking LLC—August 2013

Other

- Great White Sand Tiger Lodging Ltd.—October 2007
- Redback Energy Services, LLC—October 2011
- Redback Coil Tubing, LLC—May 2012
- Anaconda Rentals LLC, formerly White Wing Tubular Services LLC—September 2014
- WTL Oil LLC, or WTL, formerly Silverback—June 2016
- Mammoth Energy Services Inc.—June 2016
- Mammoth Energy Partners, LLC—October 2016
- Mako Acquisitions LLC—March 2017
- Stingray Energy Services LLC, or Stingray Energy Services—June 2017
- Stingray Cementing LLC—June 2017
- Tiger Shark Logistics LLC—October 2017
- Cobra Aviation Services LLC—January 2018
- Black Mamba Energy LLC—March 2018
- Stingray Cementing and Acidizing LLC, formerly RTS Energy Services LLC—June 2018
- Ivory Freight Solutions LLC—July 2018
- IFX Transport LLC—December 2018
- Air Rescue Systems LLC—December 2018
- Leopard Aviation LLC—April 2019
- Anaconda Manufacturing LLC—September 2019

Impact of the Ongoing COVID-19 Pandemic and Volatility in Commodity Prices

In March and April 2020, concurrent with the spread of COVID-19 and quarantine orders in the U.S. and worldwide, oil prices dropped sharply to below zero for the first time in history due to factors including significantly reduced demand and a shortage of storage facilities. Beginning in March 2020, in response to the COVID-19 pandemic and the depressed commodity prices, many exploration and production companies, including our customers, substantially reduced their capital expenditure budgets. As a result, demand for our oilfield services declined at the end of the first quarter of 2020 and continued to decline further throughout the remainder of 2020. Exploration and production companies set their 2021 budgets based on the prevailing prices for oil and gas at the time. Although demand for oil and natural gas and commodity prices increased during the fourth quarter of 2021, these budgets for the publicly traded exploration and production companies remained relatively unchanged throughout 2021 with any excess cash flows used for debt repayment or shareholder returns rather than to increase production, as has been the case in the past. Although activity levels for many exploration and production companies increased during the fourth quarter of 2021 and early 2022 due to the recent improvement in the U.S. and global economic activity, easing of the COVID-19 pandemic related restrictions, availability of vaccines and treatments and rising energy use and commodity prices, the emergence of the Delta COVID-19 variant in the latter part of 2021 and the subsequent surge of the highly transmissible Omicron variant continued to contribute to the economic and pricing volatility and a cautious production outlook for 2022. On July 18, 2021, the OPEC+ reached an agreement to phase out 5.8 million barrels per day of oil production cuts by September 2022 as prices of crude oil reached their highest levels in more than two years. Coordinated increases in oil supply by OPEC+ began in August 2021, increasing overall oil production by 400,000 barrels per day on a monthly basis from that point forward. Further, on January 4, 2022, OPEC+ agreed to raise its output target by 400,000 Bbl per day in February 2022, which move is expected to further boost oil supply in response to rising demand. In its report issued on February 10, 2022, OPEC noted its expectation that world oil demand will rise by 4.15 million Bbl per day in 2022, as the global economy continues to post a strong recovery from the COVID-19 pandemic. Although this demand outlook is expected to underpin oil prices, which have already seen a seven-year high in early 2022, we cannot predict the impact of these events on commodity prices and expect a competitive market for oilfield services for the foreseeable future. In addition, the current Russian/Ukrainian military conflict could result in a humanitarian crisis and have an adverse impact on the global energy and capital markets and global stability.

We have taken, and continue to take, responsible steps to protect the health and safety of our employees during the COVID-19 pandemic. We are also continuing to monitor the adverse industry and market conditions resulting from the COVID-19 pandemic and have taken mitigating steps in an effort to preserve liquidity, reduce costs and lower capital expenditures. These actions have included reducing headcount, adjusting pay and limiting spending. We will continue to take further actions that we deem to be in the best interest of the Company and our stockholders if the current conditions worsen. Given the dynamic nature of these events, we are unable to predict the ultimate impact of the COVID-19 pandemic, the volatility in commodity markets, the reduced demand for oil and oilfield services and uncertain macroeconomic conditions on our business, financial condition, results of operations, cash flows and stock price or the pace or extent of any subsequent recovery.

2021 Highlights

- Net loss of $101.4 million, or $2.18 per diluted share, and adjusted net loss of $99.3 million, or $2.13 per diluted share, for the year ended December 31, 2021. See “Non-GAAP Financial Measures” below for a reconciliation of net loss to adjusted net loss.

- Adjusted EBITDA of ($11.6) million for the year ended December 31, 2021. See “Non-GAAP Financial Measures” below for a reconciliation of net loss to Adjusted EBITDA.

- Organically started a fiber division, which was awarded a fiber installation contract with a cooperative in the Midwest in late 2021 with an expected aggregate revenue of $4.5 million throughout 2022.

- Awarded a contract by a major utility to provide engineering and design services for the building of electric vehicle charging station infrastructure with an expected aggregate revenue of $5 million over the next three years.

Overview of Our Industries

Energy Infrastructure Industry

Our infrastructure services business provides engineering, design, construction, upgrade, maintenance and repair services to the electrical infrastructure industry. We offer a broad range of services on electric transmission and distribution, or T&D, networks and substation facilities, which include engineering, design, construction, upgrade, maintenance and repair of high voltage transmission lines, substations and lower voltage overhead and underground distribution systems. Our commercial services include the installation, maintenance and repair of commercial wiring. We also provide storm repair and restoration services in response to storms and other disasters. We provide infrastructure services primarily in the northeast, southwest, midwest and western portions of the United States.

We currently have agreements in place with private utilities, public IOUs and Co-Ops. Since we commenced operations in this line of business, a substantial portion of our infrastructure revenue has been generated from storm restoration work, primarily from PREPA, due to damage caused by Hurricane Maria. On October 19, 2017, Cobra and PREPA entered into an emergency master services agreement for repairs to PREPA's electrical grid. The one-year contract, as amended, provided for payments of up to $945 million (the "first contract"). On May 26, 2018, Cobra and PREPA entered into a second one-year, $900 million master services agreement to provide additional repair services and begin the initial phase of reconstruction of the electrical power system in Puerto Rico (the "second contract"). Our work under each of the contracts with PREPA ended on March 31, 2019.

As of December 31, 2021, PREPA owed us approximately $227 million for services we performed, excluding $110.8 million of interest charged on these delinquent balances as of December 31, 2021. See Note 2. Summary of Significant Accounting Policies—Accounts Receivable to our consolidated financial statements included elsewhere in this report. PREPA is currently subject to bankruptcy proceedings, which were filed in July 2017 and are currently pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPA's ability to meet its payment obligations under the contracts is largely dependent upon funding from the Federal Emergency Management Agency, or FEMA, or other sources. On September 30, 2019, we filed a motion with the U.S. District Court for the District of Puerto Rico seeking recovery of the amounts owed to us by PREPA, which motion was stayed by the Court. On March 25, 2020, we filed an urgent motion to modify the stay order and allow our recovery of approximately $62 million in claims related to a tax gross-up provision contained in the first contract. This emergency motion was denied on June 3, 2020 and the Court extended the stay of our motion. On December 9, 2020, the Court again extended the stay of our motion and directed PREPA to file a status report by June 7, 2021. On April 6, 2021, we filed a motion to lift the stay order. Following this filing, PREPA initiated discussion with Cobra, which resulted in PREPA and Cobra filing a joint motion to adjourn all deadlines relative to the April 6, 2021 motion until the June 16, 2021 omnibus hearing as a result of PREPA's understanding that FEMA would be releasing a report in the near future relating to the first contract. The joint motion was granted by the Court on April 14, 2021. On May 26, 2021, FEMA issued a Determination Memorandum related to the first contract between Cobra and PREPA in which, among other things, FEMA raised two contract compliance issues and, as a result, concluded that approximately $47 million in costs were not authorized costs under the contract. On June 14, 2021, the Court issued an order adjourning Cobra's motion to lift the stay order to a hearing on August 4, 2021 and directing Cobra and PREPA to meet and confer in good faith concerning, among other things, (i) the May 26, 2021 Determination Memorandum issued by FEMA and (ii) whether and when a second determination memorandum is expected. The parties were further directed to file an additional status report, which was filed on July 20, 2021. On July 23, 2021, with our aid, PREPA filed an appeal of the entire $47 million that FEMA de-obligated in the May 26, 2021 Determination Memorandum. The appeal is currently pending. On August 4, 2021, the Court denied Cobra's April 6, 2021 motion to lift the stay order, extended the stay of our motion seeking recovery of amounts owed to Cobra and directed the parties to file an additional joint status report, which was filed on January 22, 2022. On January 26, 2022, the Court extended the stay and directed the parties to file a further status report by July 25, 2022.

We believe all amounts charged to PREPA were in accordance with the terms of the contracts. Further, we believe these receivables are collectible. However, in the event PREPA (i) does not have or does not obtain the funds necessary to satisfy its obligations to Cobra under the contracts, (ii) obtains the necessary funds but refuses to pay the amounts owed to us or (iii) otherwise does not pay amounts owed to us for services performed, the receivable may not be collected and our financial condition, results of operations and cash flows would be materially and adversely affected. In addition, government contracts are subject to various uncertainties, restrictions and regulations, including oversight audits and compliance reviews by government agencies and representatives. In this regard, on September 10, 2019, the U.S. District Court for the District of Puerto Rico unsealed an indictment that charged the former president of Cobra with conspiracy, wire fraud, false statements and disaster fraud. Two other individuals were also charged in the indictment. The indictment is focused on the interactions between a former FEMA official and the former President of Cobra. Neither we nor any of our subsidiaries were charged in the indictment. We are continuing to cooperate with the related investigation. We are also subject to investigations and legal proceedings related to our contracts with PREPA. Given the uncertainty inherent in the criminal litigation, investigations and legal proceedings, it is not possible at this time to determine the potential outcome or other potential impacts that they could have on us. See Note 19. Commitments and Contingencies to our consolidated financial statements included elsewhere in this report for additional information regarding these investigations and proceedings. Further, as noted above, our contracts with PREPA have concluded and we have not obtained, and there can be no assurance that we will be able to obtain, one or more contracts with other customers to replace the level of services that we provided to PREPA.

Although the COVID-19 pandemic and resulting economic conditions have not had a material impact on demand or pricing for our infrastructure services, revenues for our infrastructure services declined in 2021 as a result of certain management changes, which resulted in crew departures, as well as a decline in storm restoration activities. Our crew count declined from approximately 100 crews as of December 31, 2020 to approximately 82 crews as of December 31, 2021. During the third quarter of 2021, we made leadership changes in our infrastructure group. We are focused on cutting costs and enhancing accountability across the division, and we have already seen improvement in both areas.

Funding for projects in the infrastructure space remains strong with added opportunities expected from the Infrastructure Investment and Jobs Act, which was signed into law on November 15, 2021. We continue to pursue opportunities within this sector as we strategically structure our service offerings for growth, intending to increase our infrastructure services activity and expand both our geographic footprint and depth of projects. In late 2021, we were awarded a fiber installation contract as well as an electric vehicle charging station engineering contract. Both of these projects are currently in process.

We work for multiple utilities primarily across the northeastern, southwestern, midwestern and western portions of the United States. We believe that we are well-positioned to compete for new projects due to the experience of our infrastructure management team, combined with our vertically integrated service offerings. We are seeking to leverage this experience and our service offerings to grow our customer base and increase our revenues in the continental United States over the coming years.

Oil and Natural Gas Industry

The oil and natural gas industry has traditionally been volatile and is influenced by a combination of long-term, short-term and cyclical trends, including the domestic and international supply and demand for oil and natural gas, current and expected future prices for oil and natural gas and the perceived stability and sustainability of those prices, production depletion rates and the resultant levels of cash flows generated and allocated by exploration and production companies to their drilling, completion and related services and products budgets. The oil and natural gas industry is also impacted by general domestic and international economic conditions, political instability in oil producing countries, government regulations (both in the United States and elsewhere), levels of customer demand, the availability of pipeline capacity, storage capacity and other conditions and factors that are beyond our control. See “Recent Developments—Impact of the COVID-19 Pandemic and Volatility in Commodity Prices” above.

Demand for most of our oil and natural gas products and services depends substantially on the level of capital expenditures by companies in the oil and natural gas industry. The levels of capital expenditures of our customers are predominantly driven by the prices of oil and natural gas. As discussed above, oil prices dropped sharply throughout March and April of 2020. While improved commodity pricing has contributed to positive industry movement and increased equipment utilization, oil and natural gas prices are expected to continue to be volatile and we cannot predict if, or at what levels, commodity prices will stabilize. We experienced a weakening in demand for our oilfield services during 2019 as a result of reductions in our customers’ capital expenditure budgets. The sharp decline in oil prices beginning in March 2020, the continued volatility and strategic operating decisions by producers to curtail drilling activity have continued to adversely impact the utilization and pricing of our oilfield services.

In response to market conditions, we have temporarily shut down our cementing and acidizing operations and flowback operations beginning in July 2019, our contract drilling operations beginning in December 2019, our rig hauling operations beginning in April 2020, our coil tubing, pressure control and full service transportation operations beginning in July 2020 and our crude oil hauling operations beginning in July 2021. We continue to monitor the market to determine if and when we can recommence these services. We are currently operating two of our six pressure pumping fleets. Based on feedback from our exploration and production customers, we believe they plan to take a cautious approach with respect to their activity levels for 2022 given the recent volatility in oil prices and investor sentiment calling for activities to remain within or below cash flows. Market fundamentals are challenging for our oilfield businesses and we expect this trend to continue. Although the reported retirement of equipment across the industry may, at some point, help the market, we believe pricing and utilization for our oilfield services will remain challenging for the foreseeable future. Subject to our liquidity requirements, we expect to be ready to ramp up our oilfield service offerings when oilfield demand, pricing and margins strengthen.

We continue to closely monitor our cost structure in response to market conditions and intend to pursue additional cost savings where possible. Further, a significant portion of our revenue from our pressure pumping business had historically been derived from Gulfport. On December 28, 2019, Gulfport filed a lawsuit alleging our breach of our pressure pumping contract with Gulfport and seeking to terminate the contract and recover damages for alleged overpayments, audit costs and legal fees. Gulfport did not make the payments owed to us under this contract for any periods subsequent to its alleged December 28, 2019 termination date. Further, on November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. On September 21, 2021, we reached a settlement with Gulfport under which all litigation relating to the Stingray Pressure Pumping contract was terminated, Stingray Pressure Pumping released all claims against Gulfport and its subsidiaries with respect to Gulfport's bankruptcy proceedings and each of the parties released all claims they had against the others with respect to the litigation matters discussed above. We have not been able to obtain long-term contracts with other customers to replace our contract with Gulfport. See Note 19. Commitments and Contingencies to our consolidated financial statements included elsewhere in this report for additional information.

Natural Sand Proppant Industry

In the natural sand proppant industry, demand growth for frac sand and other proppants is primarily driven by advancements in oil and natural gas drilling and well completion technology and techniques, such as horizontal drilling and hydraulic fracturing, as well as overall industry activity growth.

In 2018 and 2019, several new and existing suppliers completed planned capacity additions of frac sand supply, particularly in the Permian Basin. The industry expansion, coupled with increased capital discipline, budget exhaustion and the impact on oil demand from the COVID-19 pandemic, caused the frac sand market to become oversupplied, particularly in finer grades. With the frac sand market oversupplied, pricing for all grades has fallen significantly from the peaks experienced throughout 2018 and during the first half of 2019. This oversupply resulted in several industry participants idling and closing high cost mines in an attempt to restore the supply and demand balance and reduce the number of industry participants. Nevertheless, demand for our sand declined significantly in the second half of 2019 and throughout 2020 as a result of completion activity falling due to lower oil demand and pricing as discussed above, increased capital discipline by our customers, budget exhaustion and the COVID-19 pandemic. Activity has rebounded modestly in 2021 as we have seen an increase in the volume of sand sold, however the prices of frac sand have continued to be depressed compared to prior levels. We cannot predict if and when pricing and demand will recover sufficiently to return our natural sand proppant services segment to profitability.

Further, as a result of adverse market conditions, production at our Muskie sand facility in Pierce County, Wisconsin has been temporarily idled since September 2018. Our contracted capacity has provided a baseline of business, which has kept our Taylor and Piranha plants operating and our costs low.

A portion of our revenue from our natural sand proppant business historically had been derived from Gulfport pursuant to a long-term contract. Gulfport did not made the payments owed to us under this contract for any periods subsequent to May 2020. In September 2020, we filed a lawsuit seeking to recover delinquent payments owed to us under this contract. On November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. On September 21, 2021, the Company and Gulfport reached a settlement under which all litigation relating to the Muskie contract was terminated and a portion of Muskie's contract claim against Gulfport was allowed under Gulfport's plan of reorganization. See Note 19. Commitments and Contingencies to our consolidated financial statements included elsewhere in this report for additional information.

Results of Operations

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

	Years Ended	
	December 31, 2021	December 31, 2020
Revenue:	(in thousands)	
Infrastructure services	$ 93,403	$ 157,751
Well completion services	84,334	88,325
Natural sand proppant services	34,860	34,360
Drilling services	4,321	7,785
Other services	18,510	28,829
Eliminations	(6,466)	(3,974)
Total revenue	228,962	313,076
Cost of revenue:		
Infrastructure services (exclusive of depreciation and amortization of $21,841 and $29,337, respectively, for 2021 and 2020)	90,559	124,555
Well completion services (exclusive of depreciation and amortization of $26,356 and $30,395, respectively, for 2021 and 2020)	64,552	47,483
Natural sand proppant services (exclusive of depreciation, depletion and accretion of $8,993 and $9,758, respectively, for 2021 and 2020)	27,232	25,955
Drilling services (exclusive of depreciation and amortization of $7,995 and $10,036, respectively, for 2021 and 2020)	6,102	10,909
Other services (exclusive of depreciation and amortization of $13,209 and $15,713, respectively, for 2021 and 2020)	16,347	27,093
Eliminations	(6,466)	(3,974)
Total cost of revenue	198,326	232,021
Selling, general and administrative expenses	78,246	67,185
Depreciation, depletion, amortization and accretion	78,475	95,317
Impairment of goodwill	891	54,973
Impairment of other long-lived assets	1,212	12,897
Operating loss	(128,188)	(149,317)
Interest expense, net	(6,406)	(5,397)
Other income, net	10,301	34,938
Loss before income taxes	(124,293)	(119,776)
Benefit for income taxes	(22,863)	(12,169)
Net loss	$ (101,430)	$ (107,607)

Revenue. Revenue for 2021 decreased $84.1 million, or 27%, to $229.0 million from $313.1 million for 2020. The decrease in total revenue is attributable to declines in revenue across all business lines other than our natural sand proppant services division. Revenue derived from related parties was $17.9 million, or 8% of our total revenue, for 2021 and $50.6 million, or 16% of our total revenue, for 2020. Substantially all of our related party revenue was derived from Gulfport under pressure pumping and sand contracts which have ended. For additional information regarding the status of these contracts and the related litigation, see “Industry Overview – Oil and Natural Gas Industry,” “Industry Overview – Natural Sand Proppant Industry” and Note 19. Commitments and Contingencies to our consolidated financial statements included elsewhere in this report. Revenue by division was as follows:

Infrastructure Services. Infrastructure services division revenue decreased $64.3 million, or 41%, to $93.4 million for 2021 from $157.8 million for 2020 primarily due to less storm activity during the year ended December 31, 2021 compared to the year ended December 31, 2020 resulting in an $58.4 million decline in storm restoration revenue. Additionally, infrastructure services revenue was negatively impacted by the decrease in crew count from approximately 100 crews as of December 31, 2020 to 82 crews as of December 31, 2021. These crew departures were driven by changes in division level management.

Well Completion Services. Well completion services division revenue decreased $4.0 million, or 5%, to $84.3 million for 2021 from $88.3 million for 2020. Revenue derived from related parties was $15 million, or 18% of total well completion revenue, for 2021 and $42.5 million, or 48% of total well completion revenue, for 2020. Substantially all of our related party revenue was derived from Gulfport under a pressure pumping contract which has ended. In 2021, we recognized revenue totaling $15 million related to the modification of our pressure pumping contract with Gulfport. For additional information regarding the status of this contract, see "Industry Overview – Oil and Natural Gas Industry" above. Intersegment revenue, consisting primarily of revenue derived from our other services and sand segment, totaled $0.1 million and $1.1 million, for 2021 and 2020, respectively.

The decrease in our well completion services revenue was primarily driven by a decline in utilization. The number of stages completed decreased 12% to 2,544 for 2021 from 2,880 for 2020. An average of 1.1 of our six fleets were active throughout 2021 compared to 1.5 fleets for 2020.

Natural Sand Proppant Services. Natural sand proppant services division revenue increased $0.5 million, or 1%, to $34.9 million for 2021, from $34.4 million for 2020. Revenue derived from related parties was $2.1 million, or 6% of total sand revenue, for 2021 and $8.4 million, or 24% of total sand revenue, for 2020. All of our related party revenue was derived from Gulfport under a sand supply contract. On November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. In 2021, we recognized revenue totaling $2 million related to the modification of our sand supply contract with Gulfport. For additional information regarding the status of this contract, see "Industry Overview – Natural Sand Proppant Industry" above. Intersegment revenue, consisting primarily of revenue derived from our well completion segment, was $4.0 million, or 11% of total sand revenue, for 2021 and a nominal amount for 2020.

The increase in our natural sand proppant services revenue was primarily attributable to a 107% increase in tons of sand sold from approximately 0.5 million tons in 2020 to 1.0 million tons in 2021 coupled with a 15% increase in average price per ton of sand sold from $14.58 in 2020 to $16.76 in 2021. Included in natural sand proppant services revenue is shortfall revenue of $12.0 million and $24.8 million, for 2021 and 2020, respectively.

Drilling Services. Drilling services division revenue decreased $3.5 million, or 44%, to $4.3 million for 2021, from $7.8 million for 2020. Revenue derived from related parties, consisting primarily of directional drilling revenue from El Toro Resources LLC, was $0.6 million for 2021 and a nominal amount for 2020.

The decline in our drilling services revenue was primarily attributable to declines in utilization for our directional drilling and rig hauling businesses. In response to market conditions, we temporarily shut down our contract land drilling operations beginning in December 2019 and our rig hauling operations beginning in April 2020.

Other Services. Revenue from other services, consisting of revenue derived from our aviation, coil tubing, pressure control, equipment rental, crude oil hauling, full service transportation, remote accommodation and equipment manufacturing, decreased $10.3 million, or 36%, to $18.5 million for 2021 from $28.8 million for 2020. Revenue derived from related parties, consisting primarily of equipment rental revenue from Gulfport and aviation revenue from Brim Equipment Leasing, Inc., or Brim, was $0.4 million, or 2% of total other services revenue, for 2021 and $1.0 million, or 3% of total other services revenue, for 2020. Intersegment revenue, consisting primarily of revenue derived from our infrastructure and well completion segments, totaled $2.2 million and $2.7 million, for 2021 and 2020, respectively.

The decrease in our other services revenue was primarily due to a decline in utilization for our equipment rental business. We rented an average of 135 pieces of equipment to customers during 2021, a decrease of 34% from an average of 204 pieces of equipment rented to customers during 2020. Additionally, utilization for our crude oil hauling and aviation businesses declined. Due to market conditions, we temporarily shut down our coil tubing and full service transportation operations beginning in July 2020 and our crude oil hauling operations beginning in July 2021.

Cost of Revenue (exclusive of depreciation, depletion, amortization and accretion expense). Cost of revenue, exclusive of depreciation, depletion, amortization and accretion expense, decreased $33.7 million from $232.0 million, or 74% of total revenue, for 2020 to $198.3 million, or 87% of total revenue, for 2021. The decrease was primarily due to a decline in activity across all of our business lines. Cost of revenue by operating division was as follows:

Infrastructure Services. Infrastructure services division cost of revenue, exclusive of depreciation and amortization expense, decreased $34.0 million from $124.6 million for 2020 to $90.6 million for 2021, primarily due to a decline in activity. As a percentage of revenue, cost of revenue, exclusive of depreciation and amortization expense of $21.9 million in 2021 and $29.4 million in 2020, was 97% and 79%, for 2021 and 2020, respectively. The increase as a percentage of revenue is primarily due to increased labor costs as a percentage of revenue.

Well Completion Services. Well completion services division cost of revenue, exclusive of depreciation and amortization expense, increased $17.1 million, or 36%, from $47.5 million for 2020 to $64.6 million for 2021 primarily due to an increase in cost of goods sold as a result of providing sand and chemicals with our service package to customers in 2021. As a percentage of revenue, our well completion services division cost of revenue, exclusive of depreciation and amortization expense of $26.4 million in 2021 and $30.4 million in 2020, was 77% and 54%, for 2021 and 2020, respectively. The increase as a percentage of revenue was primarily due to the recognition of more pressure pumping services standby revenue in 2020, of which there was a lower percentage of costs recognized compared to 2021. Additionally, during 2021 we provided sand and chemicals with our service package to customers, resulting in higher cost of goods sold as a percentage of revenue for this period in comparison to 2020.

Natural Sand Proppant Services. Natural sand proppant services division cost of revenue, exclusive of depreciation, depletion and accretion expense, increased $1.2 million, or 5%, from $26.0 million for 2020 to $27.2 million for 2021. As a percentage of revenue, cost of revenue, exclusive of depreciation, depletion and accretion expense of $9.0 million in 2021 and $9.8 million in 2020, was 78% and 76%, for 2021 and 2020, respectively.

Drilling Services. Drilling services division cost of revenue, exclusive of depreciation and amortization expense, decreased $4.8 million, or 44%, from $10.9 million for 2020 to $6.1 million for 2021, as a result of reduced activity. In response to market conditions, we have temporarily shut down our contract land drilling operations beginning in December 2019 and our rig hauling operations beginning in April 2020. As a percentage of revenue, our drilling services division cost of revenue, exclusive of depreciation and amortization expense of $8.0 million in 2021 and $10.0 million in 2020, was 139% and 116%, for 2021 and 2020, respectively. The increase as a percentage of revenue was primarily due to a decline in utilization.

Other Services. Other services cost of revenue, exclusive of depreciation and amortization expense, decreased $10.7 million, or 40%, from $27.1 million for 2020 to $16.3 million for 2021, primarily due to a decline in costs for our equipment rental, coil tubing, and full service transportation businesses as a result of reduced activity. Due to market conditions, we have temporarily shut down our coil tubing and full service transportation operations beginning in July 2020 and our crude oil hauling operations beginning in July 2021. As a percentage of revenue, cost of revenue, exclusive of depreciation and amortization expense of $13.2 million in 2021 and $15.7 million in 2020, was 88% and 94%, for 2021 and 2020, respectively. The decrease as a percentage of revenue is primarily due to a decline in equipment rental costs as a percentage of revenue.

Selling, General and Administrative Expenses. Selling, general and administrative expenses, or SG&A, represent the costs associated with managing and supporting our operations. Following is a breakout of SG&A expenses for the periods indicated (in thousands):

	Years Ended	
	December 31, 2021	**December 31, 2020**
Cash expenses:		
Compensation and benefits	$ 15,064	$ 14,876
Professional services	11,400	19,905
Other[(a)]	9,052	8,828
Total cash SG&A expense	35,516	43,609
Non-cash expenses:		
Bad debt provision	41,662	21,958
Stock based compensation	1,068	1,618
Total non-cash SG&A expense	42,730	23,576
Total SG&A expense	$ 78,246	$ 67,185

a. Includes travel-related costs, IT expenses, rent, utilities and other general and administrative-related costs.
b. The bad debt provision for the year ended December 31, 2021 includes $41.2 million related to the Stingray Pressure Pumping and Muskie contracts with Gulfport. The bad debt provision for the year ended December 31, 2020, included $19.4 million related to the voluntary petitions for relief filed on November 13, 2020, by Gulfport and certain of its subsidiaries. See Notes 2 and 19 of the Notes to the Consolidated Financial Statements.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, amortization and accretion decreased $16.8 million, or 18%, to $78.5 million for 2021 from $95.3 million in 2020. The decrease is primarily due to a decline in property and equipment depreciation expense as a result of lower capital expenditures.

Impairment of Goodwill. We recorded impairment of goodwill of $0.9 million and $55.0 million in 2021 and 2020, respectively. As a result of our annual assessment of goodwill, we determined that the carrying value of goodwill for certain of our entities exceeded their fair values at December 31, 2021, resulting in impairment expense of $0.9 million. As a result of market conditions, we performed an impairment assessment of our goodwill as of March 31, 2020. We determined that the carrying value of goodwill for certain of our entities exceeded their fair values, resulting in impairment expense of $55.0 million.

Impairment of Other Long-lived Assets. We recorded impairments of other long-lived assets of $1.2 million and $12.9 million, in 2021 and 2020, respectively. Beginning in 2021, we temporarily shut down our crude oil hauling operations, resulting in impairment of trade names of $0.5 million. Additionally, as a result of a review of intangible asset balances as of December 31, 2021, we determined the fair value of Higher Power's trade names and customer relationships was less than their carrying value, resulting in impairment expense of $0.7 million. During 2020, we recorded impairment of property and equipment, including water transfer, crude oil hauling, coil tubing and equipment rental assets, totaling $12.9 million.

Operating Loss. We reported an operating loss of $128.2 million for 2021 compared to an operating loss $149.3 million for 2020. The reduced operating loss was primarily due to the recognition of $67.9 million in impairment expenses during 2020, as compared to $2.1 million in 2021, partially offset by a $19.7 million increase in bad debt expense primarily due to the settlement with Gulfport.

Interest Expense, net. Interest expense, net increased $1.0 million to $6.4 million for 2021 from $5.4 million for 2020, primarily due to an increase in expense recognized on sale-leaseback transactions.

Other Income (Expense), net. Other income, net decreased $22.7 million during 2021 compared to 2020. During 2021, we recognized expense of $25.0 million related to an agreement to settle a legal matter and legal fees related to the matter totaling $5.4 million. This expense was partially offset by a $4.4 million increase in gains on asset disposals and a $4.4 million increase in interest on delinquent account receivables.

Income Taxes. During 2021, we recorded an income tax benefit of $22.9 million on pre-tax loss of $124.3 million compared to an income tax benefit of $12.2 million on pre-tax loss of $119.8 million for 2020. Our effective tax rate was 18.4% for 2021 compared to 10.2% for 2020. Our tax rate is affected by recurring items, such as tax rates in foreign jurisdictions and the relative amounts of income we earn in those jurisdictions, as well as discrete items, such as return to provision adjustments, goodwill impairment and changes in the valuation allowance that may not be consistent from year to year. See Note 13 to our consolidated financial statements for additional detail regarding our change in tax expense.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

	Years Ended	
	December 31, 2020	**December 31, 2019**
Revenue:	**(in thousands)**	
Infrastructure services	$ 157,751	$ 213,285
Well completion services	88,325	243,802
Natural sand proppant services	34,360	97,063
Drilling services	7,785	31,964
Other services	28,829	88,586
Eliminations	(3,974)	(49,688)
Total revenue	313,076	625,012
Cost of Revenue:		
Infrastructure services (exclusive of depreciation and amortization of $29,337 and $30,323, respectively, for 2020 and 2019)	124,555	173,551
Well completion services (exclusive of depreciation and amortization of $30,395 and $40,117, respectively, for 2020 and 2019)	47,483	206,543
Natural sand proppant services (exclusive of depreciation, depletion and accretion of $9,758 and $14,039, respectively, for 2020 and 2019)	25,955	87,652
Drilling services (exclusive of depreciation and amortization of $10,036 and $13,138, respectively, for 2020 and 2019)	10,909	36,953
Other services (exclusive of depreciation and amortization of $15,713 and $19,323, respectively, for 2020 and 2019)	27,093	88,837
Eliminations	(3,974)	(49,748)
Total cost of revenue	232,021	543,788
Selling, general and administrative expenses	67,185	51,552
Depreciation, depletion, amortization and accretion	95,317	117,033
Impairment of goodwill	54,973	33,664
Impairment of other long-lived assets	12,897	7,358
Operating loss	(149,317)	(128,383)
Interest expense, net	(5,397)	(4,958)
Other income, net	34,938	42,216
Loss before income taxes	(119,776)	(91,125)
Benefit for income taxes	(12,169)	(12,081)
Net loss	$ (107,607)	$ (79,044)

Revenue. Revenue for 2020 decreased $311.9 million, or 50%, to $313.1 million from $625.0 million for 2019. The decrease in total revenue is attributable to declines in revenue across all business lines. Revenue derived from related parties was $50.6 million, or 16% of our total revenue, for 2020 and $130.3 million, or 21% of our total revenue, for 2019. Substantially all of our related party revenue was derived from Gulfport under pressure pumping and sand contracts. For additional information regarding the status of these contracts, see “Industry Overview – Oil and Natural Gas Industry,” “Industry Overview – Natural Sand Proppant Industry” and Note 19. Commitments and Contingencies to our consolidated financial statements included elsewhere in this report. Revenue by division was as follows:

Infrastructure Services. Infrastructure services division revenue decreased $55.5 million, or 26%, to $157.8 million for 2020 from $213.3 million for 2019 primarily due to the conclusion on March 31, 2019 of the work we performed under our contracts with PREPA for repairs to Puerto Rico’s electrical grid as a result of Hurricane Maria. For additional information regarding our contracts with PREPA and our infrastructure services, see “Overview of Our Industries - Electrical Infrastructure Industry” above. Revenue from our operations in the continental United States increased $41.1 million, or 35%, to $157.8 million for 2020 from $116.7 million for 2019.

Well Completion Services. Well completion services division revenue decreased $155.7 million, or 64%, to $88.3 million for 2020 from $243.8 million for 2019. Revenue derived from related parties was $42.5 million, or 48% of total well completion revenue, for 2020 and $91.2 million, or 37% of total well completion revenue, for 2019. Substantially all of our related party revenue was derived from Gulfport under a well completion contract. On November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. In 2020, we recognized pre-petition revenue totaling $38.5 million and post-petition revenue totaling $3.9 million in accordance with the terms of this contract. For additional information regarding the status of this contract, see "Industry Overview – Oil and Natural Gas Industry" above. Intersegment revenue, consisting primarily of revenue derived from our other services and sand segment, was $0.9 million and $1.9 million, respectively, for 2020 and 2019.

The decrease in our well completion services revenue was primarily driven by a decline in pricing as well as a decline in utilization. The number of stages completed decreased 46% to 2,880 for 2020 from 5,378 for 2019. An average of 1.5 of our fleets were active throughout 2020 compared to 2.4 fleets for 2019.

Natural Sand Proppant Services. Natural sand proppant services division revenue decreased $62.7 million, or 65%, to $34.4 million for 2020, from $97.1 million for 2019. Revenue derived from related parties was $8.4 million, or 24% of total sand revenue, for 2020 and $27.7 million, or 29% of total sand revenue, for 2019. All of our related party revenue was derived from Gulfport under a sand supply contract. On November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. In 2020, we recognized pre-petition revenue totaling $6.5 million and post-petition revenue totaling $1.0 million in accordance with the terms of this contract. For additional information regarding the status of this contract, see "Industry Overview – Natural Sand Proppant Industry" above. Intersegment revenue, consisting primarily of revenue derived from our well completion segment, was nominal for 2020 and $30 million, or 31% of total sand revenue, for 2019.

The decrease in our natural sand proppant services revenue was primarily attributable to a 75% decline in tons of sand sold from approximately 2.0 million tons in 2019 to 0.5 million tons in 2020 coupled with a 51% decline in average price per ton of sand sold from $29.70 in 2019 to $14.58 in 2020. Included in natural sand proppant services revenue is shortfall revenue of $24.8 million and $2.8 million, respectively, for 2020 and 2019.

Drilling Services. Drilling services division revenue decreased $24.2 million, or 76%, to $7.8 million for 2020, from $32.0 million for 2019. Revenue derived from related parties, consisting primarily of directional drilling revenue from El Toro Resources LLC, was nominal for 2020 and $0.6 million for 2019.

The decline in our drilling services revenue was primarily attributable to declines in contract land drilling, rig hauling and directional drilling revenue of $9.2 million, $8.6 million, and $6.3 million, respectively. In response to market conditions, we temporarily shut down our contract land drilling operations beginning in December 2019 and our rig hauling operations beginning in April 2020.

Other Services. Revenue from other services, consisting of revenue derived from our aviation, coil tubing, pressure control, flowback, cementing, acidizing, equipment rental, crude oil hauling, full service transportation, remote accommodation, equipment manufacturing and infrastructure engineering and design businesses, decreased $59.8 million, or 67%, to $28.8 million for 2020 from $88.6 million for 2019. Revenue derived from related parties, consisting primarily of equipment rental revenue from Gulfport and aviation revenue from Brim Equipment Leasing, Inc., or Brim, was $1.0 million, or 3% of total other services revenue, for 2020 and $10.9 million, or 12% of total other services revenue, for 2019. Intersegment revenue, consisting primarily of revenue derived from our infrastructure and well completion segments, totaled $2.7 million and $15.2 million, respectively for 2020 and 2019.

The decrease in our other services revenue was primarily due to a decline in utilization for our equipment rental business. We rented an average of 204 pieces of equipment to customers during 2020, a decrease of 63% from an average of 557 pieces of equipment rented to customers during 2019. Additionally, utilization for our crude oil hauling and aviation businesses declined. Due to market conditions, we temporarily shut down our cementing and acidizing operations as well as our flowback operations in July 2019 and our coil tubing and full service transportation operations beginning in July 2020. These decreases were partially offset by an increase in revenue for our remote accommodations business.

Cost of Revenue (exclusive of depreciation, depletion, amortization and accretion expense). Cost of revenue, exclusive of depreciation, depletion, amortization and accretion expense, decreased $311.8 million from $543.8 million, or 87% of total revenue, for 2019 to $232.0 million, or 74% of total revenue, for 2020. The decrease was primarily due to a decline in activity across all business lines. Cost of revenue by operating division was as follows:

Infrastructure Services. Infrastructure services division cost of revenue, exclusive of depreciation and amortization expense, decreased $49.0 million from $173.6 million for 2019 to $124.6 million for 2020. The decline is due to the conclusion on March 31, 2019 of the work we performed under our contracts with PREPA for repairs to Puerto Rico's electrical grid as a result of Hurricane Maria. As a percentage of revenue, cost of revenue, exclusive of depreciation and amortization expense of $29.4 million in 2020 and $30.3 million in 2019, was 79% and 81%, respectively, for 2020 and 2019.

Well Completion Services. Well completion services division cost of revenue, exclusive of depreciation and amortization expense, decreased $159.6 million, or 77%, from $206.5 million for 2019 to $47.5 million for 2020 primarily due to a decline in activity. As a percentage of revenue, our well completion services division cost of revenue, exclusive of depreciation and amortization expense of $30.4 million in 2020 and $40.2 million in 2019, was 54% and 85%, respectively, for 2020 and 2019. The decrease was primarily due to the recognition of standby revenue during 2020, of which there was a lower percentage of costs recognized compared to 2019. Additionally, during 2019 we provided sand and chemicals with our service package to customers, resulting in higher costs of goods sold as a percentage of revenue for this period in comparison to 2020.

Natural Sand Proppant Services. Natural sand proppant services division cost of revenue, exclusive of depreciation, depletion and accretion expense, decreased $61.7 million, or 70%, from $87.7 million for 2019 to $26.0 million for 2020 primarily due to a decrease in cost of goods sold as a result of a decrease in tons of sand sold. As a percentage of revenue, cost of revenue, exclusive of depreciation, depletion and accretion expense of $9.8 million in 2020 and $14.1 million in 2019, was 76% and 90%, respectively, for 2020 and 2019. The decrease in cost as a percentage of revenue is primarily due to an increase in shortfall revenue, partially offset by a 51% decline in average price per ton of sand sold.

Drilling Services. Drilling services division cost of revenue, exclusive of depreciation and amortization expense, decreased $26.0 million, or 70%, from $37.0 million for 2019 to $10.9 million for 2020, as a result of reduced activity. In response to market conditions, we temporarily shut down our contract land drilling operations beginning in December 2019 and our rig hauling operations beginning in April 2020. As a percentage of revenue, our drilling services division cost of revenue, exclusive of depreciation and amortization expense of $10.0 million in 2020 and $13.1 million in 2019, was 140% and 116%, respectively, for 2020 and 2019. The increase was primarily due to a decline in utilization.

Other Services. Other services cost of revenue, exclusive of depreciation and amortization expense, decreased $62.7 million, or 71%, from $88.8 million for 2019 to $27.1 million for 2020, primarily due to a decline in costs for our equipment rental and crude oil hauling businesses as a result of reduced activity. Additionally, due to market conditions, we temporarily shut down our cementing and acidizing operations as well as our flowback operations beginning in July 2019 and our coil tubing, pressure control and full service transportation operations beginning in July 2020. We continue to monitor market conditions to evaluate if and when we can recommence providing these services. These declines were partially offset by an increase in costs for our equipment manufacturing business. As a percentage of revenue, cost of revenue, exclusive of depreciation and amortization expense of $15.7 million in 2020 and $19.3 million in 2019, was 93% and 101%, respectively, for 2020 and 2019.

Selling, General and Administrative Expenses. Selling, general and administrative expenses, or SG&A, represent the costs associated with managing and supporting our operations. Following is a breakout of SG&A expenses for the periods indicated (in thousands):

	Years Ended			
	December 31, 2020		December 31, 2019	
Cash expenses:				
Compensation and benefits	$	14,876	$	19,364
Professional services		19,905		17,128
Other[(a)]		8,828		10,300
Total cash SG&A expense		43,609		46,792
Non-cash expenses:				
Bad debt provision		21,958		1,434
Stock based compensation		1,618		3,326
Total non-cash SG&A expense		23,576		4,760
Total SG&A expense	$	67,185	$	51,552

a. Includes travel-related costs, IT expenses, rent, utilities and other general and administrative-related costs.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, accretion and amortization decreased $21.7 million, or 19%, to $95.3 million for 2020 from $117.0 million in 2019. The decrease is primarily due to a decline in property and equipment depreciation expense as well as a decline in depletion expense.

Impairment of Goodwill. We recorded impairment of goodwill of $55.0 million and $33.7 million, respectively, in 2020 and 2019. As a result of market conditions, we performed an impairment assessment of our goodwill as of March 31, 2020. We determined that the carrying value of goodwill for certain of our entities exceeded their fair values, resulting in impairment expense of $55.0 million. As a result of our annual assessment of goodwill, we determined that the carrying value of goodwill for certain of our entities exceeded their fair values at December 31, 2019, resulting in impairment expense of $33.7 million. During 2019, we temporarily shut down our cementing and acidizing operations, resulting in impairment of goodwill totaling $3.1 million.

Impairment of Other Long-lived Assets. We recorded impairments of other long-lived assets of $12.9 million and $7.4 million, respectively, in 2020 and 2019. During 2020, we recorded impairment of property and equipment, including water transfer, crude oil hauling, coil tubing and equipment rental assets, totaling $12.9 million. During 2019, we temporarily shut down our flowback operations, resulting in fixed asset impairments of $3.6 million during 2019. Additionally, we recorded impairment expense $3.0 million related to specified drilling rigs and $0.8 million related to WTL's customer relationship intangible asset during 2019.

Operating Loss. We reported an operating loss of $149.3 million for 2020 compared to operating loss of $128.4 million for 2019. The increased operating loss was primarily due to increases in impairment expense of $26.8 million and SG&A expense of $15.6 million, partially offset by a 15% decline in cost of revenue as a percentage of revenue.

Interest Expense, net. Interest expense, net remained relatively flat at $5.4 million and $5.0 million for 2020 and 2019, respectively.

Other Income (Expense), net. Other income, net decreased $7.3 million during 2020 compared to 2019 primarily due to a decline in the recognition of interest on trade accounts receivable pursuant to the terms of our contracts with PREPA.

Income Taxes. During 2020, we recorded an income tax benefit of $12.2 million on pre-tax loss of $119.8 million compared to income tax benefit of $12.1 million on pre-tax loss of $91.1 million for 2019. Our effective tax rate was 10.2% for 2020 compared to 13.3% for 2019. Our tax rate is affected by recurring items, such as tax rates in foreign jurisdictions and the relative amounts of income we earn in those jurisdictions, as well as discrete items, such as return to provision adjustments, goodwill impairment and changes in the valuation allowance that may not be consistent from year to year. See Note 13 to our consolidated financial statements for additional detail regarding our change in tax expense.

Non-GAAP Financial Measures

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net (loss) income before depreciation, depletion, amortization and accretion, impairment of goodwill, impairment of other long-lived assets, inventory obsolescence charges, acquisition related costs, public offering costs, equity based compensation, stock based compensation, interest expense, net, other (income) expense, net (which is comprised of the (gain) or loss on disposal of long-lived assets, interest on trade accounts receivable and certain legal expenses) and (benefit) provision for income taxes, further adjusted to add back interest on trade accounts receivable. We exclude the items listed above from net (loss) income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industries depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net (loss) income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following tables also provide a reconciliation of Adjusted EBITDA to the GAAP financial measure of net income or (loss) for each of our operating segments for the specified periods (in thousands).

Consolidated

	Years Ended December 31,		
Reconciliation of Adjusted EBITDA to net loss:	**2021**	**2020**	**2019**
Net loss	$ (101,430)	$ (107,607)	$ (79,044)
Depreciation, depletion, amortization and accretion	78,475	95,317	117,033
Impairment of goodwill	891	54,973	33,664
Impairment of other long-lived assets	1,212	12,897	7,358
Inventory obsolescence charges	—	—	1,349
Acquisition related costs	—	—	45
Public offering costs	91	—	—
Stock based compensation	1,191	1,952	4,177
Interest expense, net	6,406	5,397	4,958
Other income, net	(10,301)	(34,938)	(42,216)
Benefit for income taxes	(22,863)	(12,169)	(12,081)
Interest on trade accounts receivable	34,709	34,130	42,040
Adjusted EBITDA	$ (11,619)	$ 49,952	$ 77,283

Infrastructure Services

Reconciliation of Adjusted EBITDA to net (loss) income:	Years Ended December 31, 2021	2020	2019
Net (loss) income	$ (36,711)	$ (928)	$ 18,135
Depreciation, depletion, amortization and accretion	21,880	29,373	30,349
Impairment of goodwill	891	—	—
Impairment of other long-lived assets	665	—	—
Acquisition related costs	—	—	12
Public offering costs	39	—	—
Stock based compensation	500	580	822
Interest expense	3,925	2,794	1,674
Other income, net	(6,785)	(32,437)	(41,949)
Provision for income taxes	712	7,133	7,908
Interest on trade accounts receivable	36,551	32,214	42,040
Adjusted EBITDA	$ 21,667	$ 38,729	$ 58,991

Well Completion Services

Reconciliation of Adjusted EBITDA to net loss:	Years Ended December 31, 2021	2020	2019
Net loss	$ (58,051)	$ (69,073)	$ (39,020)
Depreciation, depletion, amortization and accretion	26,377	30,411	40,159
Impairment of goodwill	—	53,406	23,423
Impairment of other long-lived assets	—	4,203	—
Acquisition related costs	—	—	18
Public offering costs	31	—	—
Stock based compensation	333	527	1,693
Interest expense	1,107	1,130	1,228
Other expense (income), net	1,073	(2,274)	580
Interest on trade accounts receivable	(1,841)	1,888	—
Adjusted EBITDA	$ (30,971)	$ 20,218	$ 28,081

Natural Sand Proppant Services

Reconciliation of Adjusted EBITDA to net (loss) income:	Years Ended December 31, 2021	2020	2019
Net loss	$ (6,328)	$ (11,324)	$ (12,589)
Depreciation, depletion, amortization and accretion	9,005	9,771	14,050
Impairment of goodwill	—	—	2,684
Acquisition related costs	—	—	8
Public offering costs	12	—	—
Stock based compensation	202	425	812
Interest expense	474	312	193
Other (income) expense, net	(874)	1,839	67
Interest on trade accounts receivable	(1)	3	—
Adjusted EBITDA	$ 2,490	$ 1,026	$ 5,225

Drilling Services

Reconciliation of Adjusted EBITDA to net loss:	Years Ended December 31, 2021	2020	2019
Net loss	$ (11,307)	$ (16,865)	$ (26,117)
Depreciation, depletion, amortization and accretion	7,996	10,039	13,143
Impairment of other long-lived assets	—	326	2,955
Acquisition related costs	—	—	2
Public offering costs	2	—	—
Stock based compensation	76	203	361
Interest expense	293	454	862
Other income, net	(177)	(227)	(9)
Adjusted EBITDA	$ (3,117)	$ (6,070)	$ (8,803)

Other Services[a]

Reconciliation of Adjusted EBITDA to net loss:	Years Ended December 31, 2021	2020	2019
Net income (loss)	$ 10,967	$ (9,417)	$ (19,514)
Depreciation, depletion, amortization and accretion	13,217	15,722	19,332
Impairment of goodwill	—	1,567	7,557
Impairment of other long-lived assets	547	8,368	4,403
Inventory obsolescence charges	—	—	1,349
Acquisition related costs	—	—	5
Public offering costs	7	—	—
Stock based compensation	80	217	489
Interest expense, net	607	707	1,001
Other income, net	(3,538)	(1,839)	(905)
Benefit for income taxes	(23,575)	(19,302)	(19,989)
Interest on trade accounts receivable	—	25	—
Adjusted EBITDA	$ (1,688)	$ (3,952)	$ (6,272)

a. Includes results for our aviation, coil tubing, pressure control, flowback, cementing, acidizing, equipment rentals, crude oil hauling, full service transportation, remote accommodations and equipment manufacturing and corporate related activities. Our corporate related activities do not generate revenue.

Adjusted Net Loss and Adjusted Loss per Share

Adjusted net loss and adjusted basic and diluted loss per share are supplemental non-GAAP financial measures that are used by management to evaluate our operating and financial performance. Management believes these measures provide meaningful information about the Company's performance by excluding certain non-cash charges, such as impairment expense, that may not be indicative of the Company's ongoing operating results. Adjusted net loss and adjusted loss per share should not be considered in isolation or as a substitute for net loss and loss per share prepared in accordance with GAAP and may not be comparable to other similarly titled measures of other companies. The following tables provide a reconciliation of adjusted net loss and adjusted loss per share to the GAAP financial measures of net loss and loss per share for the periods specified.

	Years Ended December 31,		
	2021	**2020**	**2019**
	(in thousands, except per share amounts)		
Net loss, as reported	$ (101,430)	$ (107,607)	$ (79,044)
Impairment of goodwill	891	54,973	33,664
Impairment of other long-lived assets	1,212	12,897	7,358
Adjusted net loss	$ (99,327)	$ (39,737)	$ (38,022)
Basic loss per share, as reported	$ (2.18)	$ (2.36)	$ (1.76)
Impairment of goodwill	0.02	1.20	0.75
Impairment of other long-lived assets	0.03	0.28	0.16
Adjusted basic loss per share	$ (2.13)	$ (0.88)	$ (0.85)
Diluted loss per share, as reported	$ (2.18)	$ (2.36)	$ (1.76)
Impairment of goodwill	0.02	1.20	0.75
Impairment of other long-lived assets	0.03	0.28	0.16
Adjusted diluted loss per share	$ (2.13)	$ (0.88)	$ (0.85)

Liquidity and Capital Resources

We require capital to fund ongoing operations, including maintenance expenditures on our existing fleet of equipment, organic growth initiatives, investments and acquisitions. Our primary sources of liquidity have been cash flows from operations and borrowings under our revolving credit facility. Our primary uses of capital have been for investing in property and equipment used to provide our services and acquire complementary businesses. In July 2019, as a result of oilfield market conditions as well as other factors, which include the status of collections from PREPA, our board of directors suspended our quarterly cash dividend. Future declaration of cash dividends are subject to approval by our board of directors and may be adjusted at its discretion based on market conditions and capital availability.

As of December 31, 2021, we had outstanding borrowing under our revolving credit facility of $83.4 million.

The following table summarizes our liquidity as of the dates indicated (in thousands):

	December 31,	
	2021	2020
Cash and cash equivalents	$ 9,899	$ 14,822
Revolving credit facility availability	118,948	129,787
Less long-term debt	(85,240)	(81,338)
Less available borrowing capacity reserve	(10,000)	—
Less letter of credit facilities (bonding program)	(1,000)	(5,000)
Less letter of credit facilities (insurance programs)	(3,890)	(3,890)
Less letter of credit facilities (environmental remediation)	(3,694)	(3,694)
Less letter of credit facilities (rail car commitments)	(455)	(455)
Net working capital (less cash)[(a)]	280,651	321,328
Total	$ 305,219	$ 371,560

a. Net working capital (less cash) is a non-GAAP measure and, as of December 31, 2021, is calculated by subtracting total current liabilities of $150.2 million and cash and cash equivalents of $9.9 million from total current assets of $440.8 million. As of December 31, 2020, net working capital (less cash) is calculated by subtracting total current liabilities of $128.6 million and cash and cash equivalents of $14.8 million from total current assets of $464.7 million. Amounts include receivables due from PREPA of $337.8 million and $301.2 million and corresponding liabilities of $42.3 million and $33.5 million at December 31, 2021 and 2020, respectively.

As of March 2, 2022, we had $83.7 million in borrowings outstanding under our revolving credit facility, leaving an aggregate of $10.6 million of available borrowing capacity under this facility, after giving effect to $8.5 million of outstanding letters of credit and the requirement to maintain a $7.5 million reserve out of the available borrowing capacity.

Continued prolonged volatility in the capital, financial and/or credit markets due to the COVID-19 pandemic, volatility in commodity prices and/or adverse macroeconomic conditions may further limit our access to, or increase our cost of, capital or make capital unavailable on terms acceptable to us or at all. In addition, if we are unable to comply with the covenants under our amended revolving credit facility following the expiration of the waiver period contemplated thereunder, or obtain an additional waiver of such covenants, as discussed below, and an event of default occurs and remains uncured, our lenders would not be required to lend any additional amounts to us, could elect to increase our interest rate by 200 basis points, could elect to declare all outstanding borrowings, together with accrued and unpaid interest and fees, to be due and payable, may have the ability to require us to apply all of our available cash to repay our outstanding borrowings and may foreclose on substantially all of our assets.

Liquidity and Cash Flows

The following table sets forth our cash flows for the years indicated (in thousands):

	Years Ended December 31,		
	2021	2020	2019
Net cash (used in) provided by operating activities	$ (18,865)	$ 6,967	$ (95,318)
Net cash provided by (used in) investing activities	5,507	(2,295)	(33,224)
Net cash provided by financing activities	8,428	4,266	66,702
Effect of foreign exchange rate on cash	7	12	87
Net change in cash	$ (4,923)	$ 8,950	$ (61,753)

Operating Activities

Net cash (used in) provided by operating activities was ($18.9) million, $7.0 million and ($95.3) million, respectively, for the years ended December 31, 2021, 2020 and 2019. The decrease in operating cash flows was primarily attributable to the timing of cash inflows for accounts receivable.

Investing Activities

Net cash provided by (used in) investing activities was $5.5 million, ($2.3) million and ($33.2) million, respectively, for the years ended December 31, 2021, 2020 and 2019. Substantially all remaining cash used in investing activities was used to purchase property and equipment that is utilized to provide our services, which was partially offset by proceeds from the disposal of property and equipment.

The following table summarizes our capital expenditures by operating division for the periods indicated (in thousands):

	Years Ended December 31,		
	2021	2020	2019
Infrastructure services[(a)]	$ 627	$ 258	$ 3,456
Well completion services[(b)]	4,327	4,358	14,703
Natural sand proppant services[(c)]	484	1,073	2,877
Drilling services[(d)]	44	432	3,156
Other[(e)]	361	716	11,569
Total capital expenditures	$ 5,843	$ 6,837	$ 35,761

a. Capital expenditures primarily for truck, tooling and equipment purchases for new infrastructure crews for the years ended December 31, 2021, 2020 and 2019.
b. Capital expenditures primarily for upgrades to our pressure pumping fleet and water transfer equipment for the years ended December 31, 2021, 2020 and 2019.
c. Capital expenditures primarily for maintenance for the years ended December 31, 2021, 2020 and 2019.
d. Capital expenditures primarily for directional drilling equipment for the year ended December 31, 2020 and upgrades to our rig fleet for the year ended December 31, 2019.
e. Capital expenditures primarily for equipment for our equipment rental and crude hauling businesses for the years ended December 31, 2021, 2020 and 2019.

Financing Activities

Net cash provided by financing activities was $8.4 million, $4.3 million and $66.7 million, respectively, for the years ended December 31, 2021, 2020 and 2019. Net cash provided by financing activities for the year ended December 31, 2021 was primarily attributable to net proceeds received from sale-leaseback transactions of $6.5 million and net borrowings under our revolving credit facility of $4.2 million, partially offset by principal payment on financing leases and equipment notes of $2.3 million. Net cash provided by financing activities for the year ended December 31, 2020 was primarily attributable to net proceeds of $4.7 million received from a sale-leaseback transaction and net borrowings under our revolving credit facility of $2.6 million, principal payment on financing leases and equipment notes of $2.0 million and payment of debt issuance costs of $1.0 million. Net cash provided by financing activities for the year ended December 31, 2019 was primarily attributable to net borrowings under our revolving credit facility of $80.0 million, partially offset by dividends paid of $11.2 million.

Effect of Foreign Exchange Rate on Cash

The effect of foreign exchange rate on cash was a nominal amount for both of the years ended December 31, 2021 and 2020, and $0.1 million for 2019. The year-over-year effect was driven primarily by a favorable (unfavorable) shift in the weakness (strength) of the Canadian dollar relative to the U.S. dollar for the cash held in Canadian accounts.

Working Capital

Our working capital totaled $290.5 million and $336.1 million, respectively, at December 31, 2021 and 2020. Our cash balances totaled $9.9 million and $14.8 million, respectively, at December 31, 2021 and 2020. Included in working capital are receivables due from PREPA totaling $337.8 million and $301.2 million and corresponding liabilities of $42.3 million and $33.5 million at December 31, 2021 and 2020, respectively.

Our Revolving Credit Facility

On October 19, 2018, we and certain of our direct and indirect subsidiaries, as borrowers, entered into an amended and restated revolving credit facility, as subsequently amended, with the lenders party thereto and PNC Bank, National Association, as a lender and as administrative agent for the lenders. At December 31, 2021, we had outstanding borrowings under our revolving credit facility of $83.4 million and $16.5 million of available borrowing capacity, after giving effect to $9.0 million of outstanding letters of credit and the requirement to maintain a $10.0 million reserve out of the available borrowing capacity during the limited waiver period as discussed below. As a result of the lack of payment from PREPA, we projected that we would likely breach the leverage ratio covenant contained in our revolving credit facility for the fiscal quarter ended on September 30, 2021. On November 3, 2021, we entered into a third amendment to the revolving credit facility (the “Third Amendment”) to, among other things, (i) suspend the leverage ratio and fixed charges coverage ratio covenants for the quarters ending September 30, 2021 and December 31, 2021, (ii) permanently reduce the maximum revolving advance amount from $130 million to $120 million, (iii) add a minimum adjusted EBITDA financial covenant of $6.0 million for the quarter ending December 31, 2021, (iv) set the applicable margin on all loans at 3.50% during the limited covenant waiver period, (v) add a requirement to maintain revolver availability of not less than $10.0 million at all times during the limited covenant waiver period, (vi) permanently reduce the maximum revolving advance amount in an amount equal to fifty percent (50%) of any mandatory prepayments made with non-recurring proceeds that are received during the limited covenant waiver period, and (vii) eliminate the declaration of unrestricted subsidiaries during the limited covenant waiver period. The limited covenant waiver period commenced on the effective date of the Third Amendment and was scheduled to end on the earlier to occur of (i) May 15, 2022, (ii) our reporting compliance with both the leverage ratio and the fixed charge coverage ratio covenants for either its fiscal quarter ending September 30, 2021 or December 31, 2021, and (iii) the occurrence of any event of default after the effective date of the Third Amendment. Under the Third Amendment, we also agreed to engage an advisor during the limited covenant waiver period to advise us and our subsidiaries with regard to, among other things, efforts to achieve certain operational efficiencies, improvement in results of operations, and general business strategy, and provide assistance to us and our subsidiaries in the preparation of the supplemental reporting and information required by the Third Amendment. As of December 31, 2021, we were in compliance with the covenants under our revolving credit facility, as amended and waived by the Third Amendment.

On February 28, 2022, we entered into a fourth amendment to the revolving credit facility (the “Fourth Amendment”) to, among other things, (i) amend our financial covenants as outlined below, (ii) provide for a conditional increase of the applicable interest margin, (iii) permit certain sale-leaseback transactions, (iv) provide for a reduction in the maximum revolving advance amount in an amount equal to 50% of the PREPA claims proceeds, subject to a floor equal to the sum of eligible billed and unbilled accounts receivables, and (v) classifies the payments pursuant to our settlement agreement with MasTec Renewables Puerto Rico, LLC as restricted payments and requires $20.0 million of availability both before and after making such payments.

The financial covenants under our revolving credit facility were amended as follows:

- the leverage ratio was eliminated;
- the fixed charge coverage ratio was reduced to 0.85 to 1.0 for the six months ended June 30, 2022 and increases to 1.1 to 1.0 for the periods thereafter;
- a minimum adjusted EBITDA covenant of $4.7 million, excluding interest on the accounts receivable from PREPA, for the five months ending May 31, 2022 was added; and
- the minimum excess availability covenant was reduced to $7.5 million through the earlier of (i) March 31, 2022 or (ii) the date on which proceeds of permitted sale-leaseback transactions are received, after which the minimum excess availability covenant will increase to $10.0 million.

The Fourth Amendment also permanently waived compliance by the borrowers with the leverage ratio and fixed charge coverage ratio covenants in our revolving credit facility for the fiscal quarters ended September 30, 2021 and December 31, 2021, respectively, ending the limited covenant waiver period under the Third Amendment. For additional information regarding our revolving credit facility, see Note 10. Debt to our consolidated financial statements included elsewhere in this report.

Sale-Leaseback Transactions

On December 30, 2020, we entered into an agreement with First National Capital, LLC, or FNC, whereby we agreed to sell certain assets from our infrastructure segment to FNC for aggregate proceeds of $5.0 million. Concurrent with the sale of assets, we entered into a 36 month lease agreement whereby we will lease back the assets at a monthly rental rate of $0.1 million. On June 1, 2021, we entered into another agreement with FNC whereby we sold additional assets from our infrastructure segment to FNC for aggregate proceeds of $9.5 million and entered into a 42 month lease agreement whereby we lease back the assets at a monthly rental rate of $0.2 million. Under the agreements, we have the option to purchase the assets at the end of the lease term. We recorded a liability for the proceeds received and will continue to depreciate the assets. We imputed an interest rate so that the carrying amount of the financial liabilities will be the expected repurchase price at the end of the initial lease terms.

Aviation Note

On November 6, 2020, Leopard and Cobra Aviation entered into a 39 month promissory note agreement with Bank7, or the Aviation Note, in an aggregate principal amount of $4.6 million and received net proceeds of $4.5 million. The Aviation Note bears interest at a rate based on the Wall Street Journal Prime Rate plus a margin of 1%. Principal and interest payments of $0.1 million are due monthly, with a final payment of $0.2 million due on February 1, 2024. The Aviation Note is collateralized by Leopard and Cobra Aviation's assets, including a $1.8 million certificate of deposit. The Aviation Note contains various customary affirmative and restrictive covenants. As of December 31, 2021, we did not meet the minimum debt coverage ratio of 1.25 to 1.0 set forth in the Aviation Note. On March 2, 2022, Bank7 granted us a waiver of this event of default.

Capital Requirements and Sources of Liquidity

As we pursue our business and financial strategy, we regularly consider which capital resources are available to meet our future financial obligations and liquidity requirement. We believe that our cash on hand, operating cash flow and available borrowings under our credit facility will be sufficient to meet our short-term and long-term funding requirements, including funding our current operations, planned capital expenditures, debt service obligations, litigation settlement obligations and other known contingencies. However, future cash flows are subject to a number of variables (including receipt of payments from our customers, including PREPA). As of December 31, 2021, PREPA owed Cobra approximately $337.8 million for services performed, including $110.8 million of interest charges. Throughout 2021, we released significant data that we obtained through Freedom of Information Act requests that affirm the work performed by Cobra in Puerto Rico. We believe these documents in conjunction with the current Administration's focus on the recovery of Puerto Rico and our enhanced lobbying efforts will aid in collecting the outstanding amounts owed to us by PREPA. However, in the event PREPA (i) does not have or does not obtain the funds necessary to satisfy its obligations to Cobra under the contracts, (ii) obtains the necessary funds but refuses to pay the amounts owed to Cobra or (iii) otherwise does not pay amounts owed to Cobra for services performed, the receivable may not be collectible, which may adversely impact our liquidity.

During 2021, our capital expenditures totaled $5.8 million and included $0.6 million in our infrastructure segment primarily related to truck, tooling and equipment purchases for new crews, $4.3 million in our well completion segment primarily related to upgrades to our pressure pumping fleet and water transfer equipment, $0.5 million in our natural sand proppant services segment for various maintenance equipment and $0.4 million for our other businesses primarily related to equipment additions for our equipment rental business.

During 2022, we currently estimate that our aggregate capital expenditures will be $6 million, depending upon industry conditions and our financial resultsThese capital expenditures include $2.5 million in our infrastructure segment for assets for additional equipment, $3.0 million in our well completion segment for conversion of a portion of our fleet to include DGB capabilities and maintenance to our existing pressure pumping fleet and $0.5 million for our other divisions, primarily for additional equipment for our rental business.

Also, as noted above in this report, in response to market conditions we have (i) temporarily shut down certain of our oilfield service offerings, including coil tubing, pressure control, flowback, crude oil hauling, cementing, acidizing and land drilling services, (ii) idled certain facilities, including our sand processing plant in Pierce County, Wisconsin and (iii) reduced our workforce across all of our operations. We continue to monitor market conditions to determine if and when we will recommence these services and operations and increase our workforce. Any such recommencement and expansion will further increase our liquidity requirements in advance of revenue generation.

In addition, while we regularly evaluate acquisition opportunities, we do not have a specific acquisition budget for 2022 since the timing and size of acquisitions cannot be accurately forecasted. We continue to evaluate acquisition opportunities, including those in the renewable energy sector as well as transactions involving entities controlled by Wexford. Our acquisitions may be undertaken with cash, our common stock or a combination of cash, common stock and/or other consideration. In the event we make one or more acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital.

If we seek additional capital for any of the above or other reasons, we may do so through borrowings under our revolving credit facility, joint venture partnerships, sale-leaseback transactions, asset sales, offerings of debt or equity securities or other means. Although we expect that our sources of capital will be adequate to fund our short-term and long-term liquidity requirement, we cannot assure you that this additional capital will be available on acceptable terms or at all. If we are unable to obtain funds we need, our ability to conduct operations, make capital expenditures, satisfy debt services obligations, pay litigation settlement obligations, fund contingencies and/or complete acquisitions that may be favorable to us will be impaired, which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Contractual and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2021 (in thousands):

	Total	Less than 1 year	1-3 Years	3-5 Years	More than 5 Years
Contractual obligations:					
Revolving credit facility[a]	$ 83,370	$ —	$ 83,370	$ —	$ —
Interest and commitment fees on revolving credit facility[b]	6,671	3,712	2,959	—	—
Aviation note[c]	3,569	1,620	1,949	—	—
Legal settlement obligation[d]	20,274	20,274	—	—	—
Sale-leaseback arrangement[e]	10,565	4,382	6,183	—	—
Operating lease obligations[f]	12,532	6,220	5,241	663	408
Financing lease obligations[g]	6,549	2,004	3,226	1,319	—
Equipment financing obligations[h]	490	482	8	—	—
Purchase commitments [i]	521	395	126	—	—
Capital purchase commitments [j]	915	915	—	—	—
	$ 145,456	$ 40,004	$ 103,062	$ 1,982	$ 408

a. Excludes interest payments.
b. Assumption of revolving credit facility balance outstanding as of December 31, 2021 of $83.4 million using the weighted average interest rate as of December 31, 2021 of 4.17%
c. Assumption of an interest rate of 5%.
d. Obligation under a legal settlement, including accrued interest. See Note 19 to our consolidated financial statements.
e. Obligations under a sale-leaseback arrangement for a portion of our infrastructure segment assets.
f. Operating lease obligations primarily relate to rail cars, real estate and other equipment.
g. Financing lease obligations primarily relate to equipment for our infrastructure segment.
h. Equipment financing obligations primarily relate to vehicles and other equipment for our well completion segment.
i. Purchase commitments are comprised primarily of software subscriptions.
j. Obligations arising from capital improvements and equipment purchases.

Critical Accounting Estimates

The preparation of financial statements requires the use of judgments and estimates. Our critical accounting policies are described below to provide a better understanding of how we develop our assumptions and judgments about future events and related estimates and how they can impact our financial statements. A critical accounting estimate is one that requires our most difficult, subjective, or complex judgments and assessments and is fundamental to our results of operations. We identified our most critical accounting estimates to be:

– allowance for doubtful accounts;

– valuations of long-lived assets, including goodwill and intangible assets; and

– litigation and contingencies.

We base our estimates on historical experience and on various other assumptions we believe to be reasonable according to the current facts and circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. We believe the following are the critical accounting policies used in the preparation of our consolidated financial statements, as well as the significant estimates and judgments affecting the application of these policies. This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this report.

Allowance for Doubtful Accounts

We regularly review receivables and provide for estimated losses through an allowance for doubtful accounts. In evaluating the level of established reserves, we make judgments regarding our customers' ability to make required payments, economic events and other factors. As the financial condition of customers changes, circumstances develop, or additional information becomes available, adjustments to the allowance for doubtful accounts may be required. This process involves judgment and estimation. Accordingly, our results of operations can be affected by adjustments to the allowance due to actual write-offs that differ from estimated amounts.

As of December 31, 2021 and 2020, our allowance for doubtful accounts totaled $18.1 million and $30.1 million, respectively, which is primarily comprised of accounts receivable from Gulfport. During 2021, we wrote-off accounts receivable totaling $83.0 million, substantially all of which related to Gulfport. See Notes 2, 3 and 19 to the consolidated financial statement for further information related to Gulfport.

Our accounts receivable balance included $337.8 million and $301.2 million related to PREPA as of December 31, 2021 and 2020, respectively, which includes interest charged on delinquent balances. PREPA has not made any payments to us on their outstanding receivable since 2019. PREPA is currently subject to bankruptcy proceedings and, as a result, their ability to meet their obligations is largely dependent upon funding from the FEMA or other sources. On September 30, 2019, we filed a motion with the U.S. District Court for the District of Puerto Rico seeking recovery of the amounts owed to us by PREPA, which motion was stayed by the court. On March 25, 2020, we filed an urgent motion to modify the stay order and allow our recovery of approximately $62 million in claims related to a tax gross-up provision contained in the first contract. This emergency motion was denied on June 3, 2020 and the court extended the stay of our motion. On December 9, 2020, the Court again extended the stay of our motion and directed PREPA to file a status motion by June 7, 2021. On April 6, 2021, we filed a motion to lift the stay order. Following this filing, PREPA initiated discussion, which resulted in PREPA and Cobra filing a joint motion to adjourn all deadlines relative to the April 6, 2021 motion until the June 16, 2021 omnibus hearing as a result of PREPA's understanding that FEMA will release a report in the near future relating to the first contract. The joint motion was granted by the court on April 14, 2021. On May 26, 2021, FEMA issued a Determination Memorandum related to the first contract between Cobra and PREPA in which, among other things, FEMA raised two contract compliance issues and, as a result, concluded that approximately $47 million in costs were not authorized costs under the contract. On June 14, 2021, the Court issued an order adjourning Cobra's motion to lift the stay order to a hearing on August 4, 2021 and directing Cobra and PREPA to meet and confer in good faith concerning (i) the May 26, 2021 Determination Memorandum issued by FEMA and (ii) whether and when a second determination memorandum is expected. The parties were further directed to file an additional status report, which was filed on July 20, 2021. On July 23, 2021, with our aid, PREPA filed an appeal of the entire $47 million that FEMA de-obligated in the May 26, 2021 Determination Memorandum. On August 10, 2021, after hearing oral argument at the August 4, 2021 omnibus hearing, the Court issued an order denying Cobra's April 2021 motion to lift the stay and directing Cobra and PREPA to file a status report on January 22, 2022. On January 26, 2022, the Court issued an order directing the parties to file a further status report by July 25, 2022.

We continuously review the facts and circumstances related to this receivable to determine if an allowance is needed. We believe all amounts charged to PREPA, including interest charged on delinquent accounts receivable, were in accordance with the terms of the contracts. Further, there have been multiple reviews prepared by or on behalf of FEMA that have concluded that the amounts Cobra charged PREPA were reasonable, that PREPA adhered to Puerto Rican legal statutes regarding emergency situations and that PREPA engaged in a reasonable procurement process. As noted above, in May 2021 FEMA raised two contract compliance issues and concluded that $47 million in costs were not eligible under the contract. PREPA, however, has filed an appeal of the entire $47 million, which is currently pending. We believe these receivables are collectible and for the reasons previously described as well as other factors, no allowance was deemed necessary at December 31, 2021 or 2020. However, in the event PREPA (i) does not have or does not obtain the funds necessary to satisfy its obligations to Cobra under the contracts, (ii) obtains the necessary funds but refuses to pay the amounts owed to us or (iii) otherwise does not pay amounts owed to us for services performed, the receivable may not be collectible.

See Note 2 to our consolidated financial statements for additional detail regarding our allowance for doubtful accounts.

Valuation of Long-Lived Assets

Long-lived assets on our balance sheet include property, plant and equipment, goodwill and intangible assets. We test goodwill for impairment annually, or more frequently if events or changes in circumstances indicate that an impairment may exist. We conduct impairment tests on long-lived assets, other than goodwill, whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

Goodwill. Under generally accepted accounting principles, we have the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of one or more of our reporting units is greater than its carrying amount. If, after assessing the totality of events or circumstances, we determine it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, there is no need to perform any further testing. However, if we conclude otherwise, then we are required to perform a quantitative impairment test by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit. If the fair value of the reporting unit is less than its carrying value, an impairment loss is recorded based on that difference.

During the years ended December 31, 2021 and 2020, and 2019, we recorded goodwill impairment charges of $0.9 million, $55.0 million and $33.7 million, respectively. See Note 6 to our consolidated financial statements for details regarding the facts and circumstances that led to this impairment and how the fair value of each reporting unit was estimated, including significant assumptions used and other details.

Other Long-Lived Assets. Impairment of other long-lived assets, including property, plant and equipment and intangible assets is evaluated by measuring the carrying amount of the assets against the estimated undiscounted future cash flows associated with the assets. If such evaluations indicate that the future undiscounted cash flow from the assets is not sufficient to recover the carrying value of such assets, the assets are adjusted to their estimated fair values.

During the years ended December 31, 2021 and 2020, and 2019, we recorded impairment charges of other long-lived assets totaling $1.2 million, $12.9 million and $7.4 million, respectively. See Note 6 to our consolidated financial statements for additional details.

The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management’s judgment. A continued period of low oil and natural gas prices or continued reductions in capital expenditures by our customers would likely have an adverse impact on our utilization and the prices that we receive for our services. This could result in the recognition of future material impairment charges on the same, or additional, property and equipment if future cash flow estimates, based upon information then available to management, indicate that their carrying values are not recoverable.

Litigation and Contingencies

As discussed in Note 19 of our consolidated financial statements, we are involved in various litigation matters arising in the ordinary course of business. Accruals for litigation and contingencies are based on our assessment, including advice of legal counsel, of the expected outcome of litigation or other dispute resolution proceedings and/or the expected resolution of contingencies. For matters in which a liability is probable and reasonably estimable, we accrue an estimate for the resolution of the matter. For matters in which a liability is not probable and reasonably estimable, we do not accrue any amounts. Significant judgment is required in both the determination of probability of loss and the determination as to whether the amount is reasonably estimable. Accruals are based on information available at the time of the assessment due to the uncertain nature of such matters. As additional information becomes available, we reassess potential liabilities related to pending claims and litigation and may revise previous estimates, which could materially affect our results of operations in a given period.

New Accounting Pronouncements

Accounting Pronouncements Recently Adopted

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02 "Leases (Topic 842)" amending the current accounting for leases. Under the new provisions, all lessees will report a right of use asset and lease liability on the balance sheet for all leases with a term longer than one year, while maintaining substantially similar classifications for financing and operating leases. Lessor accounting remains substantially unchanged with the exception that no leases entered into after the effective date will be classified as leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, and interim periods within that fiscal year. We adopted this ASU effective January 1, 2019 utilizing the transition method permitted by ASU No. 2018-11 "Leases (Topic 842): Targeted Improvements", issued in August 2018, which permits an entity to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption with no adjustment made to the comparative periods presented in the consolidated financial statements. See Note 14. Leases to our consolidated financial statements included elsewhere in this annual report for the impact the adoption of this standard had on our financial statements.

In June 2018, the FASB issued ASU No. 2018-07, "Compensation - Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Accounting," which simplifies the accounting for share-based payments granted to non-employees by aligning the accounting with requirements for employee share-based compensation. Upon transition, this ASU requires non-employee awards to be measured at fair value as of the adoption date. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within that fiscal year. We adopted this ASU effective January 1, 2019 and estimated the fair value of our non-employee awards was approximately $18.9 million as of this date.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which amends current guidance on reporting credit losses on financial instruments. This ASU requires entities to reflect its current estimate of all expected credit losses. The guidance affects most financial assets, including trade accounts receivable. This ASU is effective for fiscal years beginning after December 31, 2019, with early adoption permitted. We adopted this standard effective January 1, 2020. It did not have a material impact on the our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The demand, pricing and terms for our products and services are largely dependent upon the level of activity for the U.S. oil and natural gas industry, energy infrastructure industry and natural sand proppant industry. Industry conditions are influenced by numerous factors over which we have no control, including, but not limited to: the supply of and demand for oil and natural gas services, energy infrastructure services and natural sand proppant; demand for repair and construction of transmission lines, substations and distribution networks in the energy infrastructure industry and the level of expenditures of utility companies; the level of prices of, and expectations about future prices for, oil and natural gas and natural sand proppant, as well as energy infrastructure services; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; the discovery rates of new oil and natural gas reserves and frac sand reserves meeting industry specifications and consisting of the mesh size in demand; access to pipeline, transloading and other transportation facilities and their capacity; weather conditions; domestic and worldwide economic conditions; political instability in oil-producing countries; environmental regulations; technical advances affecting energy consumption; the price and availability of alternative fuels; the ability of oil and natural gas producers and other users of our services to raise equity capital and debt financing; and merger and divestiture activity in industries in which we operate.

In March and April 2020, concurrent with the COVID-19 pandemic and quarantine orders in the U.S. and worldwide, oil prices dropped sharply to below zero for the first time in history due to factors including significantly reduced demand and a shortage of storage facilities. In 2021, U.S. oil production stabilized as commodity prices increased and demand for crude oil rebounded. Despite the recent improvement in the U.S. and global economic activity, easing of the COVID-19 pandemic related restrictions, the availability of vaccines and treatments and rising energy use and commodity prices, the U.S. production outlook remains cautious and we continue to expect the challenging market for oilfield services for the foreseeable future, which has had, and is likely to continue to have, an adverse effect on both pricing and utilization for our oilfield services and our financial condition and results of operations.

The levels of activity in the U.S. oil and natural gas exploration and production, energy infrastructure and natural sand proppant industries have been and continue to be volatile. We are unable to predict the ultimate impact the ongoing COVID-19 pandemic, the volatility in commodity prices, the challenging market for oilfield services and any adverse changes in macroeconomic conditions would have on our business, financial condition, results of operations, cash flows and stock price.

Interest Rate Risk

We had a cash and cash equivalents balance of $9.9 million at December 31, 2021. We do not enter into investments for trading or speculative purposes. We do not believe that we have any material exposure to changes in the fair value of these investments as a result of changes in interest rates. Declines in interest rates, however, will reduce future income.

Interest under our credit facility is payable at a base rate plus an applicable margin. Additionally, at our request, outstanding balances are permitted to be converted to LIBOR rate plus applicable margin tranches. LIBOR tends to fluctuate based on multiple facts, including general short-term interest rates, rates set by the U.S. Federal Reserve, which indicated plans for multiple interest rate increases in 2022, and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. The applicable margin for either the base rate or the LIBOR rate option can vary from 2.0% to 3.5%, based upon a calculation of the excess availability of the line as a percentage of the maximum credit limit. At December 31, 2021, we had outstanding borrowings under our revolving credit facility of $83.4 million with a weighted average interest rate of 4.17%. A 1% increase or decrease in the interest rate would have increased or decreased our interest expense by approximately $0.8 million per year. We do not currently hedge our interest rate exposure.

Foreign Currency Risk

Our remote accommodation business, which is included in our other services division, generates revenue and incurs expenses that are denominated in the Canadian dollar. These transactions could be materially affected by currency fluctuations. Changes in currency exchange rates could adversely affect our consolidated results of operations or financial position. We also maintain cash balances denominated in the Canadian dollar. At December 31, 2021, we had $1.5 million of cash in Canadian accounts. A 10% increase in the strength of the Canadian dollar versus the U.S. dollar would have resulted in an increase in pre-tax income of approximately $0.1 million as of December 31, 2021. Conversely, a corresponding decrease in the strength of the Canadian dollar would have resulted in a comparable increase in pre-tax income. We have not hedged our exposure to changes in foreign currency exchange rates and, as a result, could incur unanticipated translation gains and losses.

Customer Credit Risk

We are also subject to credit risk due to concentration of our receivables from several significant customers. We generally do not require our customers to post collateral. The inability, delay or failure of our customers to meet their obligations to us due to customer liquidity issues or their insolvency or liquidation may adversely affect our business, financial condition, results of operations and cash flows. This risk may be further enhanced by the ongoing COVID-19 pandemic, the volatility in commodity prices, the reduced demand for oilfield services and challenging macroeconomic conditions.

Specifically, we had receivables due from PREPA totaling $337.8 million as of December 31, 2021. PREPA is currently subject to bankruptcy proceedings pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPA's ability to meet its payment obligations under the contracts is largely dependent upon funding from the FEMA or other sources. See Note 2. Summary of Significant Accounting Policies—Accounts Receivable and —Concentrations of Credit Risk and Significant Customers and Note 19. Commitments and Contingencies—Litigation of our consolidated financial statements contained elsewhere in this annual report for additional information.

Seasonality

We provide infrastructure services in the northeast, southwest and midwest portions of the United States. We provide well completion and drilling services primarily in the Utica, Permian Basin, Eagle Ford, Marcellus, Granite Wash, Cana Woodford and Cleveland sand resource plays located in the continental U.S. We provide remote accommodation services in the oil sands in Alberta, Canada. We serve these markets through our facilities and service centers that are strategically located to serve our customers in Ohio, Texas, Oklahoma, Wisconsin, Minnesota, Kentucky and Alberta, Canada. For the years ended December 31, 2021, 2020 and 2019, we generated approximately 48%, 35% and 17%, respectively, of our revenue from our operations in Ohio, Wisconsin, Minnesota, North Dakota, Pennsylvania, West Virginia and Canada where weather conditions may be severe. As a result, our operations may be limited or disrupted, particularly during winter and spring months, in these geographic regions, which would have a material adverse effect on our financial condition and results of operations. Our operations in Oklahoma and Texas are generally not affected by seasonal weather conditions.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2021, 2020 or 2019. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Item 8. Financial Statements and Supplementary Data

The information required by this item appears beginning on page F-1 following the signature pages of this report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2021, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2021, our disclosure controls and procedures are effective.

Changes in Internal Controls Over Financial Reporting

There was no change in our internal control over financial reporting (as defined in Rules 13a-15(d) and 15d-15(d) under the Exchange Act) that occurred during the quarter ended December 31, 2021 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2021, management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, management did not identify any material weaknesses in our internal control over financial reporting and determined that we maintained effective internal control over financial reporting as of December 31, 2021.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2021. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2021, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm".

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Mammoth Energy Services, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Mammoth Energy Services, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Company as of and for the year ended December 31, 2021, and our report dated March 4, 2022 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 4, 2022

Item 9B. Other Information

On February 28, 2022, we and certain of our direct and indirect subsidiaries, as borrowers, entered into the Fourth Amendment to our amended and restated revolving credit facility, as amended, with the lenders party thereto and PNC Bank, National Association, as a lender and as administrative agent for the lenders. The Fourth Amendment to our revolving credit facility, among other things, (i) amended our financial covenants as outlined below, (ii) provided for a conditional increase of the applicable interest margin, (iii) permitted certain sale-leaseback transactions, (iv) provided for a reduction in the maximum revolving advance amount in an amount equal to 50% of the PREPA claims proceeds, subject to a floor equal to the sum of eligible billed and unbilled accounts receivables, and (v) classified the payments pursuant to our settlement agreement with MasTec Renewables Puerto Rico, LLC as restricted payments and requires $20.0 million of availability both before and after making such payments.

The financial covenants under our revolving credit facility were amended as follows:

- the leverage ratio was eliminated;
- the fixed charge coverage ratio was reduced to 0.85 to 1.0 for the six months ended June 30, 2022 and increases to 1.1 to 1.0 for the periods thereafter;
- a minimum adjusted EBITDA covenant of $4.7 million, excluding interest the accounts receivable from PREPA, for the five months ending May 31, 2022 was added; and
- the minimum excess availability covenant was reduced to $7.5 million through the earlier of (i) March 31, 2022 or (ii) the date on which proceeds of permitted sale-leaseback transactions are received, after which the minimum excess availability covenant will increase to $10.0 million.

The Fourth Amendment also permanently waived compliance by the borrowers with the leverage ratio and fixed charge coverage ratio covenants in our revolving credit facility for the fiscal quarters ended September 30, 2021 and December 31, 2021, respectively, ending the limited covenant waiver period contemplated under the third amendment to our revolving credit facility.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III.

Item 10. Directors, Executive Officers and Corporate Governance

Information required by Item 10 of Part III is incorporated herein by reference to the definitive Proxy Statement to be filed by us pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 within 120 days after the close of the year ended December 31, 2021.

We have adopted a Code of Business Conduct and Ethics that applies to directors and employees, including the Chief Executive Officer, the Chief Financial Officer, controller and persons performing similar functions. The Code of Business Conduct and Ethics is posted on our website at http://ir.mammothenergy.com/corporate-governance.cfm. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the Code of Business Conduct and Ethics by posting such information on our website at the address specified above.

Item 11. Executive Compensation

The information required by Item 11 of Part III is incorporated by reference to our definitive Proxy Statement within 120 days after the close of the year ended December 31, 2021.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by Item 12 of Part III is incorporated by reference to our definitive Proxy Statement within 120 days after the close of the year ended December 31, 2021.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by Item 13 of Part III is incorporated by reference to our definitive Proxy Statement within 120 days after the close of the year ended December 31, 2021.

Item 14. Principal Accountant Fees and Services

The information required by Item 14 of Part III is incorporated by reference to our definitive Proxy Statement within 120 days after the close of the year ended December 31, 2021.

PART IV.

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as part of this report or incorporated by reference herein:

(1) *Financial Statements*

Financial Statements

(2) *Financial Statement Schedules*

All financial statement schedules have been omitted because they are not applicable or the required disclosure is presented in the financial statements or notes thereto.

(3) *Exhibits*

Exhibit Number	Exhibit Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
4.1	Description of Securities of the Company (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K (File No. 001-37917), filed with the SEC on March 2, 2020).
4.2	Specimen Certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to the Company's Amendment No. 2 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on October 3, 2016).
4.3	Registration Rights Agreement, dated October 12, 2016, by and between the Company and Mammoth Energy Holdings, LLC (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
10.1	Advisory Services Agreement, dated as of October 19, 2016, by and between the Company and Wexford Capital LP (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
10.2	Mammoth Energy Securities, Inc. 2016 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
10.3	Form of Option Agreement (incorporated by reference to Exhibit 10.12 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.4	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.13 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.5†	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.14 to the Company's Amendment No. 2 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on October 3, 2016).
10.6	Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, executed on October 19, 2017, by the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on November 14, 2017).
10.7	Amendment No. 1 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, executed on November 1, 2017, by the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on November 14, 2017).
10.8	Amendment No. 2 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated as of December 8, 2017, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on January 31, 2018).
10.9	Amendment No. 3 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated December 21, 2017, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on January 31, 2018).
10.10	Amendment No. 4 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated as of January 28, 2018, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on January 31, 2018).
10.11	Master Subcontract Agreement, dated as of November 2, 2017, by and among Cobra Acquisitions LLC and T&E Flow Services LLC (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K (File No. 001-37917), filed with the SEC on February 28, 2018).

10.12	Equipment Lease Agreement, dated as of August 1, 2017, by and among Bison Drilling and Field Services LLC and Predator Drilling LLC (incorporated by reference to Exhibit 10.32 to the Company's Annual Report on Form 10-K (File No. 001-37917), filed with the SEC on February 28, 2018).
10.13	Equipment Lease Agreement, dated as of August 15, 2017, by and among Bison Drilling and Field Services LLC and Predator Drilling LLC (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K (File No. 001-37917), filed with the SEC on February 28, 2018).
10.14	Amendment No. 5 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated as of February 27, 2018, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.34 to the Company's Annual Report on Form 10-K (File No. 001-37917), filed with the SEC on February 28, 2018).
10.15	Master Service Contract for PREPA's Electrical Grid Repairs Hurricane Maria, executed on May 26, 2018, by the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on May 31, 2018).
10.16	Amended and Restated Revolving Credit and Security Agreement, dated as of October 19, 2018, by and among Mammoth Energy Services, Inc., certain direct and indirect subsidiaries, the lenders party thereto and PNC Bank, National Association, as a lender and administrative agent for the lenders (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on October 25, 2018).
10.17	First Amendment to Amended and Restated Revolving Credit and Security Agreement (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on November 12, 2019).
10.18	Aviation Support Services Agreement, dated December 28, 2018, by and between Brim Equipment Leasing, Inc. and Cobra Aviation Services LLC (incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 3, 2019).
10.19	General Sales Agency Agreement, dated December 21, 2018, by and between Cobra Services LLC and Brim Equipment Leasing, Inc. (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 3, 2019).
10.20	Aircraft Lease and Management Agreement (N745BW), dated December 21, 2018 by and between Cobra Aviation Services LLC and Brim Equipment Leasing, Inc. (incorporated by reference to Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 3, 2019).
10.21	Aircraft Lease and Management Agreement (N745MB), dated December 21, 2018 by and between Cobra Aviation Services LLC and Brim Equipment Leasing, Inc. (incorporated by reference to Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 3, 2019).
10.22	Second Amendment to Amended and Restated Revolving Credit and Security Agreement, dated as of February 26, 2020 (incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K (File No. 001-37917), filed with the SEC on March 2, 2020).
10.23	N745BW Helicopter Lease Agreement, dated as of January 10, 2020 and effective as of January 1, 2020, by and between Cobra Aviation Services LLC and Cobra Acquisitions LLC and Brim Equipment Leasing LLC (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 11, 2020).
10.24	N745MB Helicopter Lease Agreement, dated as of January 10, 2020 and effective as of January 1, 2020, by and between Cobra Aviation LLC and Brim Equipment Leasing LLC (incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 11, 2020).
10.25	N810LA Helicopter Lease Agreement, dated as of January 10, 2020 and effective as of January 1, 2020, by and between Cobra Aviation LLC and Brim Equipment Leasing LLC (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 11, 2020).
10.26	N902TX Helicopter Lease Agreement, dated as of January 10, 2020 and effective as of January 1, 2020, by and between Cobra Aviation LLC and Brim Equipment Leasing LLC (incorporated by reference to Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 11, 2020).
10.27	N904AF Helicopter Lease Agreement, dated as of January 10, 2020 and effective as of January 1, 2020, by and between Cobra Aviation LLC and Brim Equipment Leasing LLC (incorporated by reference to Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 11, 2020).
10.28	Third Amendment to Amended and Restated Credit Agreement, dated as of November 3, 2021, by and among the Company, certain of its subsidiaries, PNC Bank, National Association, as a lender and administrative agent for the lender, and other lenders party thereto.
10.29*	Fourth Amendment to Amended and Restated Credit Agreement, dated as of February 28, 2022, by and among the Company, certain of its subsidiaries, PNC Bank, National Association, as a lender and administrative agent for the lender, and other lenders party thereto.
21.1*	List of Significant Subsidiaries of the Company.
23.1*	John T. Boyd Company Consent.
23.2*	Consent of Grant Thornton LLP with respect to the financial statements of Mammoth Energy Services Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
95.1*	Mine Safety Disclosure Exhibit.
96.1*	Technical Report Summary for Piranha and Taylor Mines prepared by John T. Boyd Company.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

* Filed herewith.
** Furnished herewith, not filed.
\+ Management contract, compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

			MAMMOTH ENERGY SERVICES, INC.
Date:	March 4, 2022	By:	/s/ Mark Layton
			Mark Layton
			Chief Financial Officer

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

Signature	Title	Date
/s/ Arty Straehla Arty Straehla	Chief Executive Officer (principal executive officer) and Director	March 4, 2022
/s/ Mark Layton Mark Layton	Chief Financial Officer (principal financial and accounting officer)	March 4, 2022
/s/ Arthur Amron Arthur Amron	Director (Chairman of the Board)	March 4, 2022
/s/ James D. Palm James D. Palm	Director	March 4, 2022
/s/ Paul Jacobi Paul Jacobi	Director	March 4, 2022
/s/ Arthur Smith Arthur Smith	Director	March 4, 2022
/s/ Corey Booker Corey Booker	Director	March 4, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Mammoth Energy Services, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Mammoth Energy Services, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of comprehensive loss, changes in equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 4, 2022 expressed an unqualified opinion.

Basis for opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Collectability of receivable balances from the Puerto Rico Electric Power Authority

As described further in Notes 2 and 19 to the consolidated financial statements, Cobra Acquisitions LLC ("Cobra") and the Puerto Rico Electric Power Authority ("PREPA") entered into an emergency master services agreement in October 2017 and a second master service contract in May 2018 for repairs to PREPA's electrical grid due to damage caused by Hurricane Maria in 2017 (collectively, the "PREPA Contracts"). As of December 31, 2021, the consolidated financial statements include accounts receivable from PREPA for approximately $227.0 million for services performed as well as receivables of approximately $110.8 million of interest charges on delinquent balances in accordance with the terms of the PREPA Contracts (collectively, "PREPA receivable"). PREPA is subject to bankruptcy proceedings that are currently pending in the U.S. District Court for the District of Puerto Rico. Furthermore, on September 10, 2019, the U.S. District Court for the District of Puerto Rico unsealed an indictment that charged three individuals, including the former president of Cobra, with conspiracy, wire fraud, false statements and disaster fraud. The indictment is focused on the interactions between a former U.S. Department of Homeland Security - Federal Emergency Management Agency ("FEMA") official and the former president of Cobra. The Company is cooperating with the U.S. Securities and Exchange Commission and the U.S. Department of Justice in the criminal matter and neither the Company nor any of its subsidiaries were charged in the indictment. However, adverse developments in the ongoing criminal investigation and/or related litigation may affect PREPA's willingness or intent to remit payment to Cobra. We identified the collectability of the receivable balances associated with the PREPA Contracts as a critical audit matter.

The principal consideration for our determination that the collectability of the receivable balances from PREPA is a critical audit matter is the high degree of estimation uncertainty resulting from significant management judgment. Given that PREPA is subject to bankruptcy proceedings and as a result, its ability to meet its remaining obligations under the PREPA Contracts is largely dependent upon funding from FEMA or other sources, and given the related litigation described in Notes 2 and 19, management's qualitative evaluation of the collectability of the PREPA receivable and the determination of PREPA's ability and intent to remit payment required a high degree of auditor judgment and an increased extent of effort to assess the reasonableness of management's estimates and assumptions.

Our audit procedures related to the collectability of the receivable balances from PREPA included the following, among others.

- We obtained an understanding and evaluated the design and operating effectiveness of management's controls over the collectability of the receivable balances from PREPA.
- We evaluated the qualitative assessment performed by management by performing the following:
  - We inquired of management and both internal and external legal counsel to confirm our understanding of the facts and circumstances related to collectability of the PREPA receivable and status of the related litigation.
  - We corroborated the facts and circumstances by obtaining and reviewing the relevant legal documents and correspondence with PREPA officials and others involved in the oversight of PREPA.
  - We evaluated responses to inquiry letters sent to internal and external legal counsel and obtained written representations from management related to the collectability of the PREPA receivable and related litigation.
  - Through such procedures, we assessed the reasonableness of management's conclusions that PREPA has the intent and ability to pay the receivable and whether a loss was probable or reasonably possible.
- We assessed the sufficiency of management's disclosures related to the PREPA receivable and related litigation.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2012.

Oklahoma City, Oklahoma
March 4, 2022

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED BALANCE SHEETS

ASSETS	December 31, 2021	December 31, 2020
	(in thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$ 9,899	$ 14,822
Short-term investment	1,762	1,750
Accounts receivable, net	407,550	393,112
Receivables from related parties, net	88	28,461
Inventories	8,366	12,020
Prepaid expenses	12,381	13,825
Other current assets	737	758
Total current assets	440,783	464,748
Property, plant and equipment, net	176,586	251,262
Sand reserves	64,641	65,876
Operating lease right-of-use assets	12,168	20,179
Intangible assets, net	2,561	4,774
Goodwill	11,717	12,608
Deferred income tax asset	8,094	—
Other non-current assets	4,342	5,115
Total assets	$ 720,892	$ 824,562
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 37,560	$ 40,319
Accrued expenses and other current liabilities	62,516	44,408
Current operating lease liability	5,942	8,618
Current portion of long-term debt	1,468	1,165
Income taxes payable	42,748	34,088
Total current liabilities	150,234	128,598
Long-term debt, net of current portion	85,240	81,338
Deferred income tax liabilities	865	24,741
Long-term operating lease liability	5,918	11,377
Asset retirement obligations	3,720	4,746
Other long-term liabilities	11,693	10,435
Total liabilities	257,670	261,235
COMMITMENTS AND CONTINGENCIES (Note 19)		
EQUITY		
Equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 46,684,065 and 45,769,283 issued and outstanding at December 31, 2021 and 2020	467	458
Additional paid in capital	538,221	537,039
Retained earnings (deficit)	(72,535)	28,895
Accumulated other comprehensive loss	(2,931)	(3,065)
Total equity	463,222	563,327
Total liabilities and equity	$ 720,892	$ 824,562

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

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Years Ended December 31,		
	2021	2020	2019
REVENUE	(in thousands, except per share amounts)		
Services revenue	$ 182,236	$ 234,081	$ 452,594
Services revenue - related parties	15,782	43,091	102,624
Product revenue	28,799	28,404	42,105
Product revenue - related parties	2,145	7,500	27,689
Total revenue	228,962	313,076	625,012
COST AND EXPENSES			
Services cost of revenue (exclusive of depreciation, depletion, amortization and accretion of $ 69,401, $85,481 and $102,901, respectively, for 2021, 2020 and 2019)	170,275	205,657	451,206
Services cost of revenue - related parties (exclusive of depreciation, depletion, amortization and accretion of $ 0, $0 and $0, respectively, for 2021, 2020 and 2019)	531	418	4,770
Product cost of revenue (exclusive of depreciation, depletion, amortization and accretion of $ 8,993, $9,758 and $14,039, respectively, for 2021, 2020 and 2019)	27,520	25,946	87,812
Selling, general and administrative (Note 12)	77,861	66,427	49,705
Selling, general and administrative - related parties (Note 12)	385	758	1,847
Depreciation, depletion, amortization and accretion	78,475	95,317	117,033
Impairment of goodwill	891	54,973	33,664
Impairment of other long-lived assets	1,212	12,897	7,358
Total cost and expenses	357,150	462,393	753,395
Operating loss	(128,188)	(149,317)	(128,383)
OTHER INCOME (EXPENSE)			
Interest expense, net	(6,406)	(5,397)	(4,958)
Other, net	10,816	33,048	42,216
Other, net - related parties	(515)	1,890	—
Total other income	3,895	29,541	37,258
Loss before income taxes	(124,293)	(119,776)	(91,125)
Benefit for income taxes	(22,863)	(12,169)	(12,081)
Net loss	$ (101,430)	$ (107,607)	$ (79,044)
OTHER COMPREHENSIVE INCOME (LOSS)			
Foreign currency translation adjustment, net of tax of ($36), ($54) and ($203), respectively, for 2021, 2020 and 2019	134	241	775
Comprehensive loss	$ (101,296)	$ (107,366)	$ (78,269)
Net loss per share (basic) (Note 15)	$ (2.18)	$ (2.36)	$ (1.76)
Net loss per share (diluted) (Note 15)	$ (2.18)	$ (2.36)	$ (1.76)
Weighted average number of shares outstanding (Note 15)	46,428	45,644	45,011
Weighted average number of shares outstanding, including dilutive effect (Note 15)	46,428	45,644	45,011

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

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Common Stock		Retained	Additional	Accumulated Other	
	Shares	Amount	Earnings (Deficit)	Paid-In Capital	Comprehensive Loss	Total
			(in thousands)			
Balance at January 1, 2019	44,877	$ 449	$ 226,765	$ 530,919	$ (4,081)	$ 754,052
Stock based compensation	232	2	—	4,175	—	4,177
Net loss	—	—	(79,044)	—	—	(79,044)
Cash dividends declared ($0.25 per share)	—	—	(11,219)	—	—	(11,219)
Other comprehensive income	—	—	—	—	775	775
Balance at December 31, 2019	45,109	$ 451	$ 136,502	$ 535,094	$ (3,306)	$ 668,741
Stock based compensation	660	7	—	1,945	—	1,952
Net loss	—	—	(107,607)	—	—	(107,607)
Other comprehensive income	—	—	—	—	241	241
Balance at December 31, 2020	45,769	$ 458	$ 28,895	$ 537,039	$ (3,065)	$ 563,327
Stock based compensation	915	9	—	1,182	—	1,191
Net loss	—	—	(101,430)	—	—	(101,430)
Other comprehensive income	—	—	—	—	134	134
Balance at December 31, 2021	46,684	$ 467	$ (72,535)	$ 538,221	$ (2,931)	$ 463,222

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

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2021	2020	2019
Cash flows from operating activities		(in thousands)	
Net loss	$ (101,430)	$ (107,607)	$ (79,044)
Adjustments to reconcile net loss to cash (used in) provided by operating activities:			
Stock based compensation	1,191	1,952	4,177
Depreciation, depletion, amortization and accretion	78,475	95,317	117,033
Amortization of coil tubing strings	—	359	1,641
Amortization of debt origination costs	665	831	326
Bad debt expense (Note 2)	41,662	21,958	1,434
(Gain) loss on disposal of property and equipment	(5,435)	(1,379)	55
Impairment of goodwill	891	54,973	33,664
Impairment of other long-lived assets	1,212	12,897	7,358
Inventory obsolescence	—	—	1,349
Deferred income taxes	(32,005)	(12,186)	(42,639)
Other	280	(143)	(986)
Changes in assets and liabilities:			
Accounts receivable, net	(55,898)	(32,621)	(27,006)
Receivables from related parties	28,373	(40,333)	3,641
Inventories	3,654	5,103	830
Prepaid expenses and other assets	1,444	1,996	(1,040)
Accounts payable	(2,982)	2,004	(25,812)
Accrued expenses and other liabilities	12,380	3,198	(18,800)
Income taxes payable	8,658	648	(71,499)
Net cash (used in) provided by operating activities	(18,865)	6,967	(95,318)
Cash flows from investing activities:			
Purchases of property and equipment	(5,843)	(6,761)	(35,417)
Purchases of property and equipment from related parties	—	(76)	(344)
Contributions to equity investee	—	(490)	(680)
Proceeds from disposal of property and equipment	11,350	6,782	3,217
Purchase of short-term investment	—	(1,750)	—
Net cash provided by (used in) investing activities	5,507	(2,295)	(33,224)
Cash flows from financing activities:			
Borrowings on long-term debt	73,100	35,351	156,000
Repayments of long-term debt	(68,911)	(32,800)	(76,000)
Proceeds from sale-leaseback transaction	9,473	5,000	—
Payments on sale-leaseback transaction	(2,951)	(268)	—
Dividends paid	—	—	(11,219)
Principal payments on financing leases and equipment financing notes	(2,283)	(1,966)	(2,079)
Debt issuance costs	—	(1,051)	—
Net cash provided by financing activities	8,428	4,266	66,702
Effect of foreign exchange rate on cash	7	12	87
Net (decrease) increase in cash and cash equivalents	(4,923)	8,950	(61,753)
Cash and cash equivalents at beginning of period	14,822	5,872	67,625
Cash and cash equivalents at end of period	$ 9,899	$ 14,822	$ 5,872

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2021	2020	2019
Supplemental disclosure of cash flow information:	(in thousands)		
Cash paid for interest	$ 4,827	$ 4,729	$ 4,741
Cash paid (recovered) for income taxes	$ 829	$ (617)	$ 110,848
Supplemental disclosure of non-cash transactions:			
Purchases of property and equipment included in accounts payable	$ 1,535	$ 1,312	$ 2,303
Right-of-use assets obtained for financing lease liabilities	$ 1,750	$ 2,431	$ 3,721

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

1. Organization and Basis of Presentation

The accompanying consolidated financial statements were prepared in accordance with the rules and regulations of the Securities and Exchange Commission, and reflect all adjustments, which in the opinion of management are necessary for the fair presentation of the results.

Mammoth Energy Services, Inc. ("Mammoth Inc.", "Mammoth" or the "Company"), together with its subsidiaries, is an integrated, growth-oriented company serving both the oil and gas and the electric utility industries in North America and US territories. Mammoth Inc.'s infrastructure division provides engineering, design, construction, upgrade, maintenance and repair services to various public and private owned utilities. Its oilfield services division provides a diversified set of services to the exploration and production industry including well completion, natural sand and proppant and drilling services. Additionally, the Company provides aviation services, equipment rentals, crude oil hauling, remote accommodation services and equipment manufacturing. The Company was incorporated in Delaware in June 2016.

The following companies ("Operating Entities") are included in these consolidated financial statements: Bison Drilling and Field Services, LLC ("Bison Drilling"), formed November 15, 2010; Bison Trucking LLC ("Bison Trucking"), formed August 9, 2013; Anaconda Rentals LLC, formerly known as White Wing Tubular Services LLC, formed July 29, 2014; Barracuda Logistics LLC ("Barracuda"), formed October 24, 2014; Mr. Inspections LLC ("MRI"), formed January 25, 2015; Panther Drilling Systems LLC ("Panther"), formed December 11, 2012; Redback Energy Services, LLC ("Redback Energy"), formed October 6, 2011; Redback Coil Tubing, LLC ("Coil Tubing"), formed May 15, 2012; Redback Pump Down Services LLC ("Pump Down"), formed January 16, 2015; Muskie Proppant LLC ("Muskie"), formed September 14, 2011; Stingray Pressure Pumping LLC ("Stingray Pressure Pumping"), acquired November 24, 2014; Silverback Energy LLC ("Silverback"), formerly known as Stingray Logistics LLC, acquired November 24, 2014; Great White Sand Tiger Lodging Ltd. ("Sand Tiger"), formed October 1, 2007; WTL Oil LLC ("WTL"), formerly known as Silverback Energy Services LLC, formed June 8, 2016; Mammoth Equipment Leasing LLC, formed November 14, 2016; Cobra Acquisitions LLC ("Cobra"), formed January 9, 2017; Lion Power Services LLC ("Lion Power"), formerly known as Cobra Energy LLC, formed January 25, 2017; Mako Acquisitions LLC ("Mako"), formed March 28, 2017; Piranha Proppant LLC ("Piranha"), formed March 28, 2017; Higher Power Electrical LLC ("Higher Power"), acquired April 21, 2017; Stingray Energy Services LLC ("SR Energy"), acquired June 5, 2017; Stingray Cementing LLC ("Cementing"), acquired June 5, 2017; Sturgeon Acquisitions LLC ("Sturgeon"), acquired June 5, 2017; Taylor Frac, LLC ("Taylor Frac"), acquired June 5, 2017; Taylor Real Estate Investments, LLC ("Taylor RE"), acquired June 5, 2017; South River Road, LLC ("South River"), acquired June 5, 2017; 5 Star Electric, LLC ("5 Star"), acquired July 1, 2017; Tiger Shark Logistics LLC ("Tiger Shark"), formed October 20, 2017; Cobra Aviation Services LLC ("Cobra Aviation"), formed January 2, 2018; Bison Sand Logistics LLC ("Bison Sand"), formed January 8, 2018; Dire Wolf Energy Services LLC ("Dire Wolf"), formed January 8, 2018; Black Mamba Energy LLC ("Black Mamba"), formed March 28, 2018; Stingray Cementing and Acidizing LLC ("Stingray Cementing and Acidizing"), formerly known as RTS Energy Services LLC ("RTS"), acquired June 15, 2018; Aquahawk Energy LLC ("Aquahawk"), formed June 28, 2018; Ivory Freight Solutions LLC ("Ivory Freight"), formed July 26, 2018; Python Equipment LLC ("Python"), formed December 5, 2018; IFX Transport LLC ("IFX"), formed December 5, 2018; Air Rescue Systems LLC ("ARS"), acquired December 21, 2018; Leopard Aviation LLC ("Leopard"), formed April 29, 2019; Predator Aviation LLC ("Predator Aviation"), formed April 19, 2019; Anaconda Manufacturing LLC ("Anaconda"), formed July 31, 2019; Aquawolf LLC ("Aquawolf"), formed September 25, 2019; and Falcon Fiber Solutions LLC ("Falcon"), formed March 3, 2021.

Operations

The Company's infrastructure services include engineering, design, construction, upgrade, maintenance and repair services to the electrical infrastructure industry as well as repair and restoration services in response to storms and other disasters. The Company's well completion services include equipment and personnel used in connection with the completion and early production of oil and natural gas wells. The Company's natural sand proppant services include the distribution and production of natural sand proppant that is used primarily for hydraulic fracturing in the oil and gas industry. The Company's drilling services provide drilling rigs and directional tools for both vertical and horizontal drilling of oil and natural gas wells. The Company also provides other services, including aviation, equipment rentals, remote accommodations and equipment manufacturing.

Substantially all of the Company's operations are in North America. During the periods presented in this report, the Company provided its infrastructure services primarily in the northeastern, southwestern, midwestern and western portions of the United States and in Puerto Rico. The Company's infrastructure business depends on infrastructure spending on maintenance, upgrade, expansion and repair and restoration. Any prolonged decrease in spending by electric utility companies, delays or reductions in government appropriations or the failure of customers to pay their receivables could have a material adverse effect on the Company's results of operations and financial condition. During the periods presented, the Company has operated its oil and natural gas businesses in the Permian Basin, the Utica Shale, the Eagle Ford Shale, the Marcellus Shale, the Granite Wash, the SCOOP, the STACK, the Cana-Woodford Shale, the Cleveland Sand and the oil sands located in Northern Alberta, Canada. The Company's oil and natural gas business depends in large part on the conditions in the oil and natural gas industry and, specifically, on the amount of capital spending by its customers. Any prolonged increase or decrease in oil and natural gas prices affects the levels of exploration, development and production activity, as well as the entire health of the oil and natural gas industry. Continuation of or further decreases in the commodity prices for oil and natural gas would have a material adverse effect on the Company's results of operations and financial condition.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements are prepared in accordance with GAAP and include the accounts of the Company and its subsidiaries and the variable interest entities ("VIE") for which the Company is the primary beneficiary. All material intercompany accounts and transactions between the entities within the Company have been eliminated.

Variable Interest Entities

The Company consolidates a VIE when it is determined to be the primary beneficiary, which is the party that has both (i) the power to direct the activities that most significantly impact the VIE's economic performance and (ii) through its interests in the VIE, the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. See Note 11 for more information on the Company's VIEs.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include, but are not limited to, the Company's sand reserves and their impact on calculating depletion expense, allowance for doubtful accounts, asset retirement obligations, reserves for self-insurance, depreciation and amortization of property and equipment, amortization of intangible assets and future cash flows, fair values used to assess recoverability and impairment of long-lived assets, including goodwill, estimates of income taxes and the estimated effects of litigation and other contingencies.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period financial statement presentation. The Company adopted a new accounting policy related to the classification of certain legal expenses. For matters related to ongoing operations, the Company continues to present legal expense as selling, general and administrative. For matters determined to be unrelated to ongoing operations, the Company classifies the legal expenses according to the nature of the underlying matter. The Company believes that this new accounting policy will more accurately present legal expenses on its consolidated statement of comprehensive loss. The adoption of this policy resulted in the recognition of approximately $5.4 million of legal expenses related to a certain legal settlement, which is included in Other, net on the consolidated statement of comprehensive loss for the year ended December 31, 2021. See Note 19 for additional information.

Cash and Cash Equivalents and Short-Term Investment

All highly liquid investments with an original maturity of three months or less are considered cash equivalents. The Company maintains its cash accounts in financial institutions that are insured by the Federal Deposit Insurance Corporation, with the exception of cash held by Sand Tiger in a Canadian financial institution. At December 31, 2021, we had $1.5 million, in Canadian dollars, of cash in Canadian accounts. Cash balances from time to time may exceed the insured amounts; however, the Company has not experienced any losses in such accounts and does not believe it is exposed to any significant credit risks on such accounts. The Company's short-term investment consists of a certificate of deposit with a maturity over 90 days.

Accounts Receivable

Accounts receivable include amounts due from customers for services performed or goods sold. The Company grants credit to customers in the ordinary course of business and generally does not require collateral. Prior to granting credit to customers, the Company analyzes the potential customer's risk profile by utilizing a credit report, analyzing macroeconomic factors and using its knowledge of the industry, among other factors. Most areas in the continental United States in which the Company operates provide for a mechanic's lien against the property on which the service is performed if the lien is filed within the statutorily specified time frame. Customer balances are generally considered delinquent if unpaid by the 30th day following the invoice date and credit privileges may be revoked if balances remain unpaid. Interest on delinquent trade accounts receivable is recognized in other, net on the consolidated statement of comprehensive loss when chargeable and collectability is reasonably assured.

During the period October 2017 through March 2019, the Company provided infrastructure services in Puerto Rico under master services agreements entered into by Cobra, one of the Company's subsidiaries, with the Puerto Rico Electric Power Authority ("PREPA") to perform repairs to PREPA's electrical grid as a result of Hurricane Maria. During the years ended December 31, 2021, 2020 and 2019, the Company charged interest on delinquent trade accounts receivable pursuant to the terms of its agreements with PREPA totaling $36.6 million, $32.2 million and $42.0 million, respectively. These amounts are included in other, net on the consolidated statement of comprehensive loss. Included in "accounts receivable, net" on the condensed consolidated balance sheets as of December 31, 2021 and 2020 were interest charges of $110.8 million and $74.3 million, respectively.

Allowance for Doubtful Accounts

The Company regularly reviews receivables and provides for expected losses through an allowance for doubtful accounts. In evaluating the level of established reserves, the Company makes judgments regarding its customers' ability to make required payments, economic events and other factors. As the financial condition of customers changes, circumstances develop, or additional information becomes available, adjustments to the allowance for doubtful accounts may be required. In the event the Company expects that a customer may not be able to make required payments, the Company would increase the allowance through a charge to income in the period in which that determination is made. If it is determined that previously reserved amounts are collectible, the Company would decrease the allowance through a credit to income in the period in which that determination is made. Uncollectible accounts receivable are periodically charged against the allowance for doubtful accounts once a final determination is made regarding their collectability.

Following is a roll forward of the allowance for doubtful accounts for the years ended December 31, 2021, 2020 and 2019 (in thousands):

Balance, January 1, 2019	$	5,198
Additions charged to bad debt expense		1,771
Recoveries of receivables previously charged to bad debt expense		(337)
Deductions for uncollectible receivables written off		(1,478)
Balance, December 31, 2019		5,154
Additions charged to bad debt expense		22,705
Additions charged to other selling, general and administrative expense		3,950
Additions charged to other, net - related parties		1,427
Recoveries of receivables previously charged to bad debt expense		(747)
Deductions for uncollectible receivables written off		(2,350)
Balance, December 31, 2020		30,139
Additions charged to bad debt expense		41,873
Additions charged to revenue		27,071
Additions charged to other selling, general and administrative expense		273
Additions charged to other income (expense), net - related parties		515
Additions charged to other income (expense), net		1,474
Recoveries of receivables previously charged to bad debt expense		(211)
Deductions for uncollectible receivables written off		(83,049)
Balance, December 31, 2021	$	18,085

The Company has made specific reserves consistent with Company policy which resulted in additions to allowance for doubtful accounts totaling $0.7 million, $3.3 million and $1.8 million, respectively, for the years ended December 31, 2021, 2020 and 2019. These additions were charged to bad debt expense based on the factors described above. Additionally, during the year ended December 31, 2021, the Company recorded additions to allowance for doubtful accounts of $0.3 million related to insurance claim receivables for its directors and officers liability policy. The Company will continue to pursue collection until such time as final determination is made consistent with Company policy.

Gulfport

The Company's subsidiaries Stingray Pressure Pumping and Muskie were party to a pressure pumping contract and a sand supply contract, respectively, with Gulfport Energy Corporation ("Gulfport"). On November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. Following is a roll forward of the allowance for doubtful accounts specifically related to Gulfport (in thousands):

Balance, January 1, 2020		—
Additions charged to bad debt expense		19,395
Additions charged to other selling, general and administrative expense		1,759
Additions charged to other, net - related parties		1,427
Balance, December 31, 2020		22,581
Additions charged to bad debt expense		41,196
Additions charged to revenue		27,070
Additions charged to other income (expense), net - related parties		1,842
Deductions for uncollectible receivables written off		(80,975)
Balance, December 31, 2021	$	11,714

The Company had net accounts receivable due from Gulfport totaling $0.1 million as of December 31, 2021, which is included in "accounts receivable, net" on the consolidated balance sheets. See Notes 3 and 19 for additional information.

PREPA

As of December 31, 2021 and 2020, PREPA owed the Company $337.8 million and $301.2 million, respectively, which includes interest charged on delinquent balances. PREPA is currently subject to bankruptcy proceedings, which were filed in July 2017 and are currently pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPA's ability to meet its payment obligations is largely dependent upon funding from the Federal Emergency Management Agency ("FEMA") or other sources. On September 30, 2019, Cobra filed a motion with the U.S. District Court for the District of Puerto Rico seeking recovery of the amounts owed to Cobra by PREPA, which motion was stayed by the Court. On March 25, 2020, Cobra filed an urgent motion to modify the stay order and allow the recovery of approximately $61.7 million in claims related to a tax gross-up provision contained in the emergency master service agreement, as amended, that was entered into with PREPA on October 19, 2017. This emergency motion was denied on June 3, 2020 and the Court extended the stay of our motion. On December 9, 2020, the Court again extended the stay of our motion and directed PREPA to file a status report by June 7, 2021. On April 6, 2021, Cobra filed a motion to lift the stay order. Following this filing, PREPA initiated discussion with Cobra, which resulted in PREPA and Cobra filing a joint motion to adjourn all deadlines relative to the April 6, 2021 motion until the June 16, 2021 omnibus hearing as a result of PREPA's understanding that FEMA would be releasing a report in the near future relating to the emergency master service agreement between PREPA and Cobra that was executed on October 19, 2017. The joint motion was granted by the Court on April 14, 2021. On May 26, 2021, FEMA issued a Determination Memorandum related to the first contract between Cobra and PREPA in which, among other things, FEMA raised two contract compliance issues and, as a result, concluded that approximately $47 million in costs were not authorized costs under the contract. On June 14, 2021, the Court issued an order adjourning Cobra's motion to lift the stay order to a hearing on August 4, 2021 and directing Cobra and PREPA to meet and confer in good faith concerning, among other things, (i) the May 26, 2021 Determination Memorandum issued by FEMA and (ii) whether and when a second determination memorandum is expected. The parties were further directed to file an additional status report, which was filed on July 20, 2021. On July 23, 2021, with the aid of Mammoth, PREPA filed an appeal of the entire $47 million that FEMA de-obligated in the May 26, 2021 Determination Memorandum. The appeal is currently pending. On August 4, 2021, the Court denied Cobra's April 6, 2021 motion to lift the stay order, extended the stay of our motion seeking recovery of amounts owed to Cobra and directed the parties to file an additional joint status report, which was filed on January 22, 2022. On January 26, 2022, the Court extended the stay and directed the parties to file a further status report by July 25, 2022.

The Company believes all amounts charged to PREPA, including interest charged on delinquent accounts receivable, were in accordance with the terms of the contracts. Further, there have been multiple reviews prepared by or on behalf of FEMA that have concluded that the amounts Cobra charged PREPA were reasonable, that PREPA adhered to Puerto Rican legal statutes regarding emergency situations, and that PREPA engaged in a reasonable procurement process. As noted above, in May 2021 FEMA raised two contract compliance issues and concluded that $47 million in costs were not eligible under the contract. PREPA, however, has filed an appeal of the entire $47 million, which is currently pending. The Company believes these receivables are collectible and for the reasons previously described as well as other factors, no allowance was deemed necessary at December 31, 2021 or 2020. However, in the event PREPA (i) does not have or does not obtain the funds necessary to satisfy its obligations to Cobra under the contracts, (ii) obtains the necessary funds but refuses to pay the amounts owed to the Company or (iii) otherwise does not pay amounts owed to the Company for services performed, the receivable may not be collectible.

Inventory
Inventory consists of raw sand and processed sand available for sale, raw materials, chemicals and other products sold as a bi-product of completion and production operations and supplies used in performing services. Inventory is stated at the lower of cost or market (net realizable value) on an average cost basis. The Company assesses the valuation of its inventories based upon specific usage, future utility, obsolescence and other factors.

Inventory manufactured at the Company's sand production facilities includes direct excavation costs, processing costs and overhead allocation. Stockpile tonnages are calculated by measuring the number of tons added and removed from the stockpile. Costs are calculated on a per ton basis and are applied to the stockpiles based on the number of tons in the stockpile. Inventory transported for sale at the Company's terminal facility includes the cost of purchased or manufactured sand, plus transportation related charges.

Coil tubing strings of various widths, diameters and lengths are included in inventory. The strings are used in providing specialized services to customers who are primarily operators of oil or gas wells and are used at various rates based on factors such as well conditions (i.e. pressure and friction), vertical and horizontal length of the well, running speed of the string in the well and total running feet accumulated to the string. The Company obtains usage information from data acquisition software and other established assessment methods and attempts to amortize the strings over their estimated useful life. In no event will a string be amortized over a period longer than 12 months. Amortization of coil strings is included in services cost of revenue in the consolidated statements of comprehensive loss and totaled $0.4 million and $1.6 million for the years ended December 31, 2020 and 2019, respectively. We did not recognize any amortization of coil strings for the year ended December 31, 2021.

See Note 4 for additional disclosure related to inventory.

Prepaid Expenses
Prepaid expenses primarily consist of insurance costs and rail car freight and lease expense. These costs are expensed over the periods that they benefit.

Property and Equipment
Property and equipment, including renewals and betterments, are capitalized and stated at cost, while maintenance and repairs that do not increase the capacity, improve the efficiency or safety, or improve or extend the useful life are charged to operations as incurred. Disposals are removed at cost, less accumulated depreciation, and any resulting gain or loss is recorded in operations. Depreciation is calculated using the straight-line method over the shorter of the estimated useful life, or the remaining lease term, as applicable. Depreciation does not begin until property and equipment is placed in service. Once placed in service, depreciation on property and equipment continues while being repaired, refurbished, or between periods of deployment.

Sand Reserves
Sand reserve costs include engineering, mineralogical studies and other related costs to develop the mine, the removal of overburden to initially expose the mineral and building access ways. Exploration costs are expensed as incurred and classified as product cost of revenue. Capitalization of mine development project costs begins once the deposit is classified as proven and probable reserves. Drilling and related costs are capitalized for deposits where proven and probable reserves exist and the activities are directed at obtaining additional information on the deposit or converting non-reserve minerals to proven and probable reserves and the benefit is to be realized over a period greater than one year. Mining property and development costs are amortized using the units-of-production method on estimated measured tons in in-place reserves. The impact of revisions to reserve estimates is recognized on a prospective basis.

Long-Lived Assets
The Company reviews long-lived assets for recoverability in accordance with the provisions of Financial Accounting Standards Board ("FASB") Accounting Standard Codification ("ASC") 360, *Impairment or Disposal of Long-Lived Assets*, which requires that long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. Recoverability of assets is measured by comparing the carrying amount of an asset to future undiscounted net cash flows expected to be generated by the asset. These evaluations for impairment are significantly impacted by estimates of revenues, costs and expenses and other factors. If long-lived assets are considered to be impaired, the impairment to be recognized is measured by the amount in which the carrying amount of the assets exceeds the fair value of the assets. See Note 6 for additional disclosure related to impairment of long-lived assets.

Goodwill
Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that goodwill might be impaired. If it is determined that an impairment exists, an impairment charge is recognized for the excess of carrying value over implied fair value. The fair value is determined using a combination of the income and market approaches. See Notes 6 and 7 for additional disclosures related to goodwill.

Other Non-Current Assets
Other non-current assets primarily consist of deferred financing costs on our credit facility (see Note 10), sales tax receivables and our equity method investment (see Note 8). Investments are accounted for under the equity method in circumstances where the Company has the ability to exercise significant influence over the operating and investing policies of the investee, but does not have control. Under the equity method, the Company recognizes its share of the investee's earnings in its consolidated statements of comprehensive loss. Investments are evaluated for impairment and a charge to earnings is recognized when any identified impairment is determined to be other than temporary.

Asset Retirement Obligations
Mine reclamation costs, future remediation costs for inactive mines and other contractual site remediation costs are accrued based on management's best estimate at the end of each period of the costs expected to be incurred at a site. Such cost estimates include, where applicable, ongoing care, maintenance and monitoring costs. Changes in estimates are reflected in earnings in the period an estimate is revised.

Following is a roll forward of the Company's asset retirement obligations for the years ended December 31, 2021 and 2020 (in thousands):

	December 31,	
	2021	2020
Balance as of beginning of period	$ 4,746	$ 4,241
Additions and revisions of prior estimates	(385)	372
Accretion expense	146	115
Liabilities settled	(782)	—
Foreign currency translation adjustment	(5)	18
Asset retirement obligation as of end of period	$ 3,720	$ 4,746

Amortizable Intangible Assets
Intangible assets subject to amortization include customer relationships and trade names. Customer relationships are amortized based on an estimated attrition factor and trade names are amortized over their estimated useful lives. See Notes 6 and 7 for additional disclosures related to intangible assets.

Fair Value of Financial Instruments
The Company's financial instruments consist of cash and cash equivalents, short-term investments, trade receivables, trade payables, amounts receivable or payable to related parties and long-term debt. The carrying amount of cash and cash equivalents, trade receivables, trade payables and receivables and payables from related parties approximates fair value because of the short-term nature of the instruments. The fair value of long-term debt approximates its carrying value because the cost of borrowing fluctuates based upon market conditions.

Revenue Recognition
The timing of revenue recognition may differ from contract billing or payment schedules, resulting in revenues that have been earned but not billed ("unbilled revenue") or amounts that have been billed, but not earned ("deferred revenue"). The Company had $22.0 million and $32.3 million, respectively, of unbilled revenue included in accounts receivable, net in the consolidated balance sheets at December 31, 2021 and 2020. The Company had a nominal amount and $1.5 million, respectively, of unbilled revenue included in receivables from related parties, net in the consolidated balance sheets at December 31, 2021 and 2020. The Company had $3.2 million and $8.3 million, respectively, of deferred revenue included in accrued expenses and other current liabilities in the consolidated balance sheets at December 31, 2021 and 2020.

Loss per Share
Loss per share is computed by dividing net loss by the weighted average number of outstanding shares. See Note 15.

Equity-based Compensation
The Company measures equity-based payments at fair value on the date of grant and expenses the value of these equity-based payments in compensation expense over the applicable vesting periods. See Note 16.

Stock-based Compensation
The Company's stock-based compensation program consists of restricted stock units granted to employees and restricted stock units granted to non-employee directors under the Mammoth Energy Services, Inc. 2016 Incentive Plan (the "2016 Plan"). The Company recognizes in its financial statements the cost of employee services received in exchange for restricted stock based on the fair value of the equity instruments as of the grant date. In general, this value is amortized over the vesting period; for grants with a non-substantive service condition, this value is recognized immediately. Amounts are recognized in cost of revenue and selling, general and administrative expenses. See Note 17.

Income Taxes

The Company’s operations are included in a consolidated federal income tax return and other state returns. Accordingly, the Company has recognized deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases for all our subsidiaries as if each entity were a corporation, regardless of its actual characterization for U.S. federal income tax purposes.

Under FASB ASC 740, *Income Taxes*, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of deferred tax assets and liabilities as a result of a change in tax rate are recognized in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized. To assess that likelihood, the Company uses estimates and judgments regarding future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. Certain income from our infrastructure services segment and income from our remote accommodations business is subject to foreign income taxes, and such taxes are provided in the financial statements pursuant to FASB ASC 740.

The Company evaluates tax positions taken or expected to be taken in preparation of its tax returns and disallows the recognition of tax positions that do not meet a “more likely than not” threshold of being sustained upon examination by the taxing authorities. The Company recorded an unrecognized tax benefit of $1.0 million during the year ended December 31, 2021 related to the 2020 tax year returns in Puerto Rico. No uncertain tax positions existed at December 31, 2020. It is the Company’s policy to recognize interest and applicable penalties related to uncertain tax positions in income tax expense.

Litigation and Contingencies

Accruals for litigation and contingencies are reflected in the consolidated financial statements based on management’s assessment, including advice of legal counsel, of the expected outcome of litigation or other dispute resolution proceedings and/or the expected resolution of contingencies. Liabilities for estimated losses are accrued if the potential loss from any claim or legal proceeding is considered probable and the amount can be reasonably estimated. Significant judgment is required in both the determination of probability of loss and the determination as to whether the amount is reasonably estimable. Accruals are based only on information available at the time of the assessment due to the uncertain nature of such matters. As additional information becomes available, management reassesses potential liabilities related to pending claims and litigation and may revise its previous estimates.

Foreign Currency Translation

For foreign operations, assets and liabilities are translated at the period-end exchange rate and income statement items are translated at the average exchange rate for the period. Resulting translation adjustments are recorded within accumulated other comprehensive loss. Assets and liabilities denominated in foreign currencies, if any, are re-measured at the balance sheet date. Transaction gains or losses are included as a component of current period earnings.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. Management has established procedures for the ongoing evaluation of the Company’s operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed as incurred. Liabilities are recorded when environmental costs are probable and the costs can be reasonably estimated. The Company maintains insurance which may cover in whole or in part certain environmental expenditures. As of December 31, 2021 and 2020, there were no probable environmental matters.

Other Comprehensive Loss

Comprehensive loss consists of net loss and other comprehensive loss. Other comprehensive loss included certain changes in equity that are excluded from net loss. Specifically, cumulative foreign currency translation adjustments are included in accumulated other comprehensive loss.

Concentrations of Credit Risk and Significant Customers

Financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents in excess of federally insured limits and trade receivables. Following is a summary of our significant customers based on accounts receivable balances at December 31, 2021 and 2020 and revenues derived for the years ended December 31, 2021, 2020 and 2019:

	REVENUES			ACCOUNTS RECEIVABLE	
	Years Ended December 31,			At December 31,	
	2021	2020	2019	2021	2020
Customer A[(a)]	— %	— %	15 %	83 %	71 %
Customer B[(b)]	7 %	16 %	20 %	— %	7 %
Customer C[(c)]	3 %	15 %	— %	— %	6 %

a. Customer A is a third-party customer. Revenues and the related accounts receivable balances earned from Customer A were derived from the Company's infrastructure services segment. Accounts receivable for Customer A also includes receivables due for interest charged on delinquent accounts receivable.

b. Customer B was a related-party customer until June 29, 2021. Revenues earned from this customer prior to June 29, 2021 are included in services revenue - related parties and product revenue - related parties on the consolidated statements of comprehensive loss. The related accounts receivable are included in accounts receivable, net on the consolidated balance sheet at December 31, 2021 and receivables due from related parties, net at December 31, 2020. Revenues and the related accounts receivable balances earned from Customer B were derived from the Company's well completion services segment, natural sand proppant services segment and other businesses. Accounts receivable for Customer B also included receivables due for interest charged on delinquent accounts receivable.

c. Customer C is a third-party customer. Revenues and the related accounts receivable balances earned from Customer C were derived from the Company's infrastructure services segment.

Recent Accounting Pronouncements

Accounting Pronouncements Recently Adopted

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02 "Leases (Topic 842)" amending the current accounting for leases. Under the new provisions, all lessees will report a right of use asset and lease liability on the balance sheet for all leases with a term longer than one year, while maintaining substantially similar classifications for financing and operating leases. Lessor accounting remains substantially unchanged with the exception that no leases entered into after the effective date will be classified as leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, and interim periods within that fiscal year. The Company adopted this ASU effective January 1, 2019 utilizing the transition method permitted by ASU No. 2018-11 "Leases (Topic 842): Targeted Improvements", issued in August 2018, which permits an entity to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption with no adjustment made to the comparative periods presented in the consolidated financial statements. See Note 14 for the impact the adoption of this standard had on the Company's financial statements.

In June 2018, the FASB issued ASU No. 2018-07, "Compensation - Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Accounting," which simplifies the accounting for share-based payments granted to non-employees by aligning the accounting with requirements for employee share-based compensation. Upon transition, this ASU requires non-employee awards to be measured at fair value as of the adoption date. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within that fiscal year. The Company adopted this ASU effective January 1, 2019 and estimates the fair value of its non-employee awards (see Note 16) was approximately $18.9 million as of this date.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which amends current guidance on reporting credit losses on financial instruments. This ASU requires entities to reflect its current estimate of all expected credit losses. The guidance affects most financial assets, including trade accounts receivable. This ASU is effective for fiscal years beginning after December 31, 2019, with early adoption permitted. The Company adopted this standard effective January 1, 2020. It did not have a material impact on the Company's consolidated financial statements.

3. Revenues

The Company's primary revenue streams include infrastructure services, well completion services, natural sand proppant services, drilling services and other services, which includes coil tubing, pressure control, flowback, cementing, acidizing, equipment rentals, full service transportation, crude oil hauling, remote accommodations and equipment manufacturing. See Note 20 for the Company's revenue disaggregated by type.

Certain of the Company’s customer contracts include provisions entitling the Company to a termination penalty when the customer invokes its contractual right to terminate prior to the contract’s nominal end date. The termination penalties in the customer contracts vary, but are generally considered substantive for accounting purposes and create enforceable rights and obligations throughout the stated duration of the contract. The Company accounts for a contract cancellation as a contract modification in the period in which the customer invokes the termination provision. The determination of the contract termination penalty is based on the terms stated in the related customer agreement. As of the modification date, the Company updates its estimate of the transaction price using the expected value method, subject to constraints, and recognizes the amount over the remaining performance period.

Infrastructure Services
Infrastructure services are typically provided pursuant to master service agreements, repair and maintenance contracts or fixed price and non-fixed price installation contracts. Pricing under these contracts may be unit priced, cost-plus/hourly (or time and materials basis) or fixed price (or lump sum basis). Generally, the Company accounts for infrastructure services as a single performance obligation satisfied over time. In certain circumstances, the Company supplies materials that are utilized during the jobs as part of the agreement with the customer. The Company accounts for these infrastructure agreements as multiple performance obligations satisfied over time. Revenue is recognized over time as work progresses based on the days completed or as the contract is completed. Under certain customer contracts in our infrastructure services segment, the Company warranties equipment and labor performed for a specified period following substantial completion of the work.

Well Completion Services
Well completion services are typically provided based upon a purchase order, contract or on a spot market basis. Services are provided on a day rate, contracted or hourly basis. Generally, the Company accounts for well completion services as a single performance obligation satisfied over time. In certain circumstances, the Company supplies proppant that is utilized for pressure pumping as part of the agreement with the customer. The Company accounts for these pressure pumping agreements as multiple performance obligations satisfied over time. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Generally, revenue is recognized over time upon the completion of each segment of work based upon a completed field ticket, which includes the charges for the services performed, mobilization of the equipment to the location and personnel.

Pursuant to a contract with Gulfport, Stingray Pressure Pumping agreed to provide Gulfport with use of up to two pressure pumping fleets for the period covered by the contract. Under this agreement, performance obligations were satisfied as services were rendered based on the passage of time rather than the completion of each segment of work. Stingray Pressure Pumping had the right to receive consideration from this customer even if circumstances prevent us from performing work. All consideration owed to Stingray Pressure Pumping for services performed during the contractual period is fixed and the right to receive it is unconditional. On December 28, 2019, Gulfport filed a legal action in Delaware state court seeking the termination of this contract and monetary damages. Further, on November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. On March 22, 2021, Gulfport listed the Stingray Pressure Pumping contract on its master rejection schedule filed with the bankruptcy court. The Company determined that these factors changed the scope of the contract, accelerated the duration of, and otherwise changed the rights and obligations of each party to the contract. As a result, the Company accounted for this as a contract modification during the three months ended March 31, 2021. Stingray Pressure Pumping used the expected value method to estimate unliquidated damages totaling $37.9 million, which resulted in the recognition of net revenue totaling $14.8 million and bad debt expense of $2.9 million on previously recognized revenue during the three months ended March 31, 2021. On September 21, 2021, the Company and Gulfport reached a settlement under which all litigation relating to the Stingray Pressure Pumping contract will be terminated. Stingray Pressure Pumping released all claims against Gulfport and its subsidiaries with respect to Gulfport’s bankruptcy proceedings and each of the parties released all claims they had against the others with respect to the litigation matters discussed in Note 19. As a result of this settlement agreement, during the three months ended September 30, 2021, the Company wrote off its remaining receivable related to the Stingray Pressure Pumping claim resulting in bad debt expense and other expense of $31.0 million and $1.3 million, respectively. Gulfport was a related party until June 29, 2021. On June 29, 2021, pursuant to the terms of its plan of reorganization, all of the Company’s shares that Gulfport owned were transferred to a trust for the benefit of certain of Gulfport’s creditors. The revenue recognized related to this agreement is included in “services revenue - related parties” in the accompanying consolidated statement of comprehensive loss and the related accounts receivable is included in “receivables due from related parties” as of December 31, 2020. See Notes 12 and 19 below.

Additional revenue is generated through labor charges and the sale of consumable supplies that are incidental to the service being performed. Such amounts are recognized ratably over the period during which the corresponding goods and services are consumed.

Natural Sand Proppant Services

The Company sells natural sand proppant through sand supply agreements with its customers. Under these agreements, sand is typically sold at a flat rate per ton or a flat rate per ton with an index-based adjustment. The Company recognizes revenue at the point in time when the customer obtains legal title to the product, which may occur at the production facility, rail origin or at the destination terminal.

Certain of the Company's sand supply agreements contain a minimum volume commitment related to sand purchases whereby the Company charges a shortfall payment if the customer fails to meet the required minimum volume commitment. These agreements may also contain make-up provisions whereby shortfall payments can be applied in future periods against purchased volumes exceeding the minimum volume commitment. If a make-up right exists, the Company has future performance obligations to deliver excess volumes of product in subsequent periods. In accordance with ASC 606, if the customer fails to meet the minimum volume commitment, the Company will assess whether it expects the customer to fulfill its unmet commitment during the contractually specified make-up period based on discussions with the customer and management's knowledge of the business. If the Company expects the customer will make-up deficient volumes in future periods, revenue related to shortfall payments will be deferred and recognized on the earlier of the date on which the customer utilizes make-up volumes or the likelihood that the customer will exercise its right to make-up deficient volumes becomes remote. As of December 31, 2021 and 2020, the Company had deferred revenue totaling $3.0 million and $7.9 million, respectively, related to shortfall payments. These amounts are included in accrued expenses and other current liabilities on the consolidated balance sheet. If the Company does not expect the customer will make-up deficient volumes in future periods, the breakage model will be applied and revenue related to shortfall payments will be recognized when the model indicates the customer's inability to take delivery of excess volumes. During the years ended December 31, 2021, 2020 and 2019, the Company recognized revenue totaling $12.0 million, $24.8 million and $2.8 million, respectively, related to shortfall payments.

In certain of the Company's sand supply agreements, the customer obtains control of the product when it is loaded into rail cars and the customer reimburses the Company for all freight charges incurred. The Company has elected to account for shipping and handling as activities to fulfill the promise to transfer the sand. If revenue is recognized for the related product before the shipping and handling activities occur, the Company accrues the related costs of those shipping and handling activities.

Pursuant to its contract with Gulfport, Muskie has agreed to sell and deliver specified amounts of sand to Gulfport. In September 2020, Muskie filed a lawsuit against Gulfport to recover delinquent payments due under this agreement. On November 13, 2020, Gulfport filed petitions for voluntary relief under chapter 11 of the Bankruptcy Code. On March 22, 2021, Gulfport listed the Muskie contract on its master rejection schedule filed with the bankruptcy court. The Company determined that these factors changed the scope of the contract, accelerated the duration of, and otherwise changed the rights and obligations of each party to the contract. As a result, the Company accounted for this as a contract modification during the three months ended March 31, 2021. Muskie used the expected value method to estimate unliquidated damages totaling $8.5 million, which resulted in the recognition of net revenue totaling $2.1 million and bad debt expense of $1.0 million on previously recognized revenue during the three months ended March 31, 2021. On September 21, 2021, the Company and Gulfport reached a settlement under which all litigation relating to the Muskie contract was terminated, each of the parties released all claims they had against the others with respect to the litigation matters discussed in Note 19 and Muskie's contract claim against Gulfport was allowed under Gulfport's plan of reorganization in the amount of $3.1 million. As a result of this settlement agreement, Muskie recognized bad debt expense of $0.2 million during the third quarter of 2021. As of December 31, 2021, Muskie had net accounts receivable due from Gulfport totaling $0.1 million, which includes a nominal amount of interest on delinquent accounts receivable. Gulfport was a related party until June 29, 2021. The revenue recognized related to this agreement is included in "product revenue - related parties" in the accompanying consolidated statement of comprehensive loss and the related accounts receivable is included in "accounts receivable, net" in the consolidated balance sheets as of December 31, 2021 and "receivables due from related parties" as of December 31, 2020. See Notes 12 and 19 below.

Drilling Services

Contract drilling services were provided under daywork contracts. Directional drilling services, including motor rentals, are provided on a day rate or hourly basis, and revenue is recognized as work progresses. Performance obligations are satisfied over time as the work progresses based on the measure of output. Mobilization revenue and costs were recognized over the days of actual drilling. As a result of market conditions, the Company temporarily shut down its contract land drilling operations beginning in December 2019 and its rig moving operations beginning in April 2020.

Other Services
During the periods presented, the Company also provided aviation, coil tubing, pressure control, flowback, cementing, acidizing, equipment rentals, crude oil hauling, full service transportation, remote accommodations and equipment manufacturing, which are reported under other services. As a result of market conditions, the Company temporarily shut down its cementing and acidizing operations as well as its flowback operations beginning in July 2019, its coil tubing, pressure control and full service transportation operations beginning in July 2020 and its crude oil hauling operations beginning in July 2021. The Company's other services are typically provided based upon a purchase order, contract or on a spot market basis. Services are provided on a day rate, contracted or hourly basis. Performance obligations for these services are satisfied over time and revenue is recognized as the work progresses based on the measure of output. Jobs for these services are typically short-term in nature and range from a few hours to multiple days.

Practical Expedients
The Company does not disclose the value of unsatisfied performance obligations for (i) contracts with an original expected length of one year or less and (ii) contracts in which variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied distinct good or service that forms part of a single performance obligation.

Contract Balances
Following is a rollforward of the Company's contract liabilities (in thousands):

Balance, January 1, 2019	$	4,304
Deduction for recognition of revenue		(4,827)
Increase for deferral of shortfall payments		8,442
Increase for deferral of customer prepayments		675
Deduction of shortfall payments due to contract renegotiations		(1,350)
Balance, December 31, 2019		7,244
Deduction for recognition of revenue		(25,047)
Increase for deferral of shortfall payments		25,436
Increase for deferral of customer prepayments		648
Balance, December 31, 2020		8,281
Deduction for recognition of revenue		(12,329)
Increase for deferral of shortfall payments		7,023
Increase for deferral of customer prepayments		275
Balance, December 31, 2021	$	3,250

The Company did not have any contract assets as of December 31, 2021, December 31, 2020 or December 31, 2019.

Performance Obligations
Revenue recognized in the current period from performance obligations satisfied in previous periods was a nominal amount for the years ended December 31, 2021, 2020 and 2019. As of December 31, 2021, the Company had unsatisfied performance obligations totaling $1.7 million, which will be recognized over the next6 months.

4. Inventories

Inventories consist of raw sand and processed sand available for sale, chemicals and other products sold as a bi-product of completion and production operations and supplies used in performing services. Inventory is stated at the lower of cost or net realizable value on an average cost basis. The Company assesses the valuation of its inventories based upon specific usage, future utility, obsolescence and other factors. A summary of the Company's inventories is shown below (in thousands):

	December 31,	
	2021	2020
Supplies	$ 4,557	$ 6,312
Raw materials	701	613
Work in process	2,435	3,478
Finished goods	673	1,617
Total inventory	$ 8,366	$ 12,020

5. Property, Plant and Equipment

Property, plant and equipment include the following (in thousands):

		December 31,	
	Useful Life	2021	2020
Pressure pumping equipment	3-5 years	$ 220,414	$ 217,945
Drilling rigs and related equipment	3-15 years	111,478	113,146
Machinery and equipment	7-20 years	166,873	172,272
Buildings[(a)]	15-39 years	46,006	48,776
Vehicles, trucks and trailers	5-10 years	103,982	111,911
Coil tubing equipment	4-10 years	7,592	8,541
Land	N/A	13,417	13,417
Land improvements	15 years or life of lease	10,133	10,133
Rail improvements	10-20 years	13,793	13,793
Other property and equipment[(b)]	3-12 years	18,235	18,640
		711,923	728,574
Deposits on equipment and equipment in process of assembly[(c)]		3,300	3,191
		715,223	731,765
Less: accumulated depreciation[(d)]		538,637	480,503
Total property, plant and equipment, net		$ 176,586	$ 251,262

a. Included in Buildings at each of December 31, 2021 and 2020 are costs of $ 7.6 million related to assets under operating leases.

b. Included in Other property and equipment at each of December 31, 2021 and 2020 are costs of $ 6.0 million related to assets under operating leases.

c. Deposits on equipment and equipment in process of assembly represents deposits placed with vendors for equipment that is in the process of assembly and purchased equipment that is being outfitted for its intended use. The equipment is not yet placed in service.

d. Includes accumulated depreciation of $ 6.6 million and $ 5.0 million at December 31, 2021 and 2020, respectively, related to assets under operating leases.

Proceeds from customers for horizontal and directional drilling services equipment, damaged or lost down-hole are reflected in revenue with the carrying value of the related equipment charged to cost of service revenues and are reported as cash inflows from investing activities in the statement of cash flows. For the years ended December 31, 2021, 2020 and 2019, proceeds from the sale of equipment damaged or lost down-hole were $0.3 million, $0.7 million, and a nominal amount, respectively, and gain on sales of equipment damaged or lost down-hole were $0.3 million, $0.7 million, and a nominal amount, respectively.

Proceeds from assets sold or disposed of as well as the carrying value of the related equipment are reflected in other, net on the consolidated statement of comprehensive loss. For the years ended December 31, 2021, 2020 and 2019, proceeds from the sale of equipment were $11.2 million, $6.1 million and $3.2 million, respectively, and gains (losses) from the sale or disposal of equipment were $5.1 million, $0.7 million and ($0.1) million, respectively.

A summary of depreciation, depletion, amortization and accretion expense is shown below (in thousands):

	Years Ended December 31,		
	2021	2020	2019
Depreciation expense	$ 76,093	$ 93,332	$ 112,435
Accretion and depletion expense	1,381	970	3,477
Amortization expense	1,001	1,015	1,121
Depreciation, depletion, amortization and accretion	$ 78,475	$ 95,317	$ 117,033

6. Impairments

Impairment of Goodwill

Under GAAP, the Company has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of one or more of its reporting units is greater than its carrying amount. If, after assessing the totality of events or circumstances, the Company determines it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, there is no need to perform any further testing. However, if the Company concludes otherwise, then it is required to perform a quantitative impairment test by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit. If the fair value of the reporting unit is less than its carrying value, an impairment loss is recorded based on that difference.

The Company performed the qualitative assessment described above during the fourth quarter of 2021. Based on this assessment, the Company concluded that it was more likely than not that the fair value of the Stingray Pressure Pumping, Silverback and Aviation reporting units was greater than their carrying value. Accordingly, no further testing was required on these units. Additionally, the Company concluded that the carrying value for its infrastructure reporting unit was greater than its fair value. To determine fair value of the infrastructure reporting unit at December 31, 2021, the Company used the income approach. The income approach estimates the fair value based on anticipated cash flows that are discounted using a weighted average cost of capital. As a result, the Company impaired goodwill associated with 5 Star and Higher Power, resulting in a $0.9 million impairment charge for 2021.

Oil prices declined significantly in March 2020 as a result of geopolitical events that increased the supply of oil in the market as well as effects of the COVID-19 pandemic. As a result, the Company determined that it was more likely than not that the fair value of certain of its reporting units were less than their carrying value. Therefore, the Company performed an interim goodwill impairment test. The Company impaired goodwill associated with Stingray Pressure Pumping, Silverback and WTL, resulting in a $55.0 million impairment charge during the first quarter of 2020. The Company performed an assessment of goodwill during the fourth quarter of 2020 and determined that the fair value of its goodwill was greater than its carrying value. Therefore, no additional impairment was necessary at December 31, 2020. To determine fair value, the Company used a combination of the income and market approaches. The income approach estimates the fair value based on anticipated cash flows that are discounted using a weighted average cost of capital. The market approach estimates the fair value using comparative multiples, which involves significant judgment in the selection of the appropriate peer group companies and valuation multiples.

The Company performed its annual assessment of goodwill during the fourth quarter of 2019 and determined that the carrying value of goodwill for certain of its entities was greater than their fair values. As a result, the Company impaired goodwill associated with Stingray Pressure Pumping, SR Energy, Taylor Frac and Cobra Aviation, resulting in a $30.5 million impairment charge in 2019. To determine fair value at December 31, 2019, the Company used a combination of the income and market approaches. The income approach estimates the fair value based on anticipated cash flows that are discounted using a weighted average cost of capital. The market approach estimates the fair value using comparative multiples, which involves significant judgment in the selection of the appropriate peer group companies and valuation multiples. Additionally, during the third quarter of 2019, the Company temporarily shut down its cementing and acidizing operations. As a result, the Company recognized goodwill impairment expense of $3.2 million associated with Cementing and Stingray Cementing and Acidizing. The fair value was measured using an income approach.

Impairment of Other Long-Lived Assets

A summary of impairment of other long-lived assets is as follows (in thousands):

	December 31,		
	2021	**2020**	**2019**
Water transfer equipment	$ —	$ 4,203	$ —
Crude oil hauling equipment	—	3,275	—
Coil tubing equipment	—	2,160	—
Flowback equipment	—	1,514	—
Rental equipment	—	1,308	—
Drilling rigs and related equipment	—	—	2,955
Other property, plant and equipment	—	437	3,557
Intangible assets	1,212	—	846
	$ 1,212	$ 12,897	$ 7,358

Due to market conditions, the Company has temporarily shut down its crude oil hauling operations beginning in July 2021. As a result, the Company recognized impairment of trade names totaling $0.5 million, which is included in impairment of other long-lived assets on the consolidated statements of comprehensive loss. The Company performed a review of its intangible asset balances as of December 31, 2021 and determined the fair value of Higher Power's trade names and customer relationships was less than their carrying value, resulting in an additional impairment expense of $0.7 million at year-end.

Oil prices declined significantly in March 2020 as a result of geopolitical events that increased the supply of oil in the market as well as effects of the COVID-19 pandemic. As a result, the Company determined that it was more likely than not that the fair value of certain of its oilfield services assets were less than their carrying value. Therefore, the Company performed an interim impairment test. As a result of the test, the Company recorded impairments totaling $12.9 million to its fixed assets during the first quarter of 2020. The Company measured the fair values of these assets using direct and indirect observable inputs (Level 2) based on a market approach.

For the year ended December 31, 2019, the Company recognized impairments related to drilling rig assets and other property, plant and equipment of $3.0 million and $3.6 million, respectively. These assets were deemed impaired based on future expected cash flows of the equipment. The Company measured the fair value of its drilling rig assets at December 31, 2019 using direct and indirect observable inputs (Level 2) based on a market approach. The Company measured the fair values of its other property, plant and equipment at December 31, 2019 using direct and indirect observable inputs (Level 2) based on a market approach. The Company determined the fair value of WTL's non-contractual customer relationships was less than their carrying value, resulting in impairment expense of $0.8 million during the year ended December 31, 2019. Additionally, during the third quarter of 2019, the Company temporarily shut down its flowback operations, resulting in impairment of non-contractual customer relationships of $0.1 million.

The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management's judgment. A continued period of low oil and natural gas prices or continued reductions in capital expenditures by our customers would likely have an adverse impact on our utilization and the prices that we receive for our services. This could result in the recognition of future material impairment charges on the same, or additional, property and equipment if future cash flow estimates, based upon information then available to management, indicate that their carrying values are not recoverable.

7. Goodwill and Intangible Assets

Goodwill

Changes in the net carrying amount of goodwill by reporting segment (see Note 20) for the years ended December 31, 2021 and 2020 are presented below (in thousands):

	Infrastructure	Well Completion	Sand	Other	Total
Balance as of January 1, 2020					
Goodwill	$ 891	$ 86,043	$ 2,684	$ 14,830	$ 104,448
Accumulated impairment losses	—	(23,423)	(2,684)	(10,760)	(36,867)
	891	62,620	—	4,070	67,581
Acquisitions	—	—	—	—	—
Impairment losses[(a)]	—	(53,406)	—	(1,567)	(54,973)
Balance as of December 31, 2020					
Goodwill	891	86,043	2,684	14,830	104,448
Accumulated impairment losses	—	(76,829)	(2,684)	(12,327)	(91,840)
	891	9,214	—	2,503	12,608
Acquisitions	—	—	—	—	—
Impairment losses[(a)]	(891)	—	—	—	(891)
Balance as of December 31, 2021					
Goodwill	891	86,043	2,684	14,830	104,448
Accumulated impairment losses	(891)	(76,829)	(2,684)	(12,327)	(92,731)
	$ —	$ 9,214	$ —	$ 2,503	$ 11,717

a. See Note 6 for a description of impairment losses recognized.

Intangible Assets

The Company had the following definite lived intangible assets recorded as of the dates presented below (in thousands):

	December 31, 2021	December 31, 2020
Customer relationships	$ —	$ 1,050
Trade names	7,850	9,063
Less: accumulated amortization - customer relationships	—	(642)
Less: accumulated amortization - trade names	(5,289)	(4,697)
Intangible assets, net	$ 2,561	$ 4,774

Amortization expense for intangible assets was $1.0 million, $1.0 million and $1.1 million for the years ended December 31, 2021, 2020 and 2019, respectively. The Company recognized impairment of intangible assets totaling $1.2 million and $0.8 million, respectively, for the years ended December 31, 2021 and 2019. See Note 6 for a description of these impairment losses.

The original lives of trade names range from10 to 20 years and as of December 31, 2021 the remaining average useful life was3.95 years.

Aggregated expected amortization expense for the future periods is expected to be as follows (in thousands):

Year ended December 31:		Amount
2022	$	779
2023		779
2024		710
2025		91
2026		91
Thereafter		111
	$	2,561

8. Equity Method Investment

On December 21, 2018, Cobra Aviation and Wexford Partners Investment Co. LLC (“Wexford Investment”), a related party, formed a joint venture under the name of Brim Acquisitions LLC (“Brim Acquisitions”) to acquire all outstanding equity interest in Brim Equipment for a total purchase price of approximately $2.0 million. Cobra Aviation owns a 49% economic interest and Wexford Investment owns a 51% economic interest in Brim Acquisitions, and each member contributed its pro rata portion of Brim Acquisitions initial capital of $2.0 million. Brim Acquisitions, through Brim Equipment, owns four commercial helicopters and leases five commercial helicopters for operations, which it uses to provide a variety of services, including short haul, aerial ignition, hoist operations, aerial photography, fire suppression, construction services, animal/capture/survey, search and rescue, airborne law enforcement, power line construction, precision long line operations, pipeline construction and survey, mineral and seismic exploration, and aerial seeding and fertilization.

The Company uses the equity method of accounting to account for its investment in Brim Acquisitions, which had a carrying value of approximately $.4 million and $3.7 million, respectively, at December 31, 2021 and 2020. The investment is included in other non-current assets on the consolidated balance sheets. The Company recorded equity method adjustments to its investment for its share of Brim Acquisitions’ (loss) income of ($0.3) million, $0.6 million, and $1.0 million respectively, for the years ended December 31, 2021, 2020 and 2019, respectively, which is included in other, net on the consolidated statements of comprehensive loss. The Company made additional investments totaling $0.5 million and $0.7 million during the years ended December 31, 2020 and 2019, respectively.No additional investments were made during the year ended December 31, 2021.

9. Accrued Expenses and Other Current Liabilities and Other Long-Term Liabilities

Accrued expense and other current liabilities and Other long-term liabilities included the following (in thousands):

	December 31,	
	2021	**2020**
Accrued Expenses and Other Current Liabilities		
Accrued legal settlement[(a)]	$ 18,966	$ —
State and local taxes payable	13,772	13,838
Financed insurance premiums[(b)]	9,852	10,394
Deferred revenue	3,250	8,281
Accrued compensation and benefits	5,133	3,710
Insurance reserves	1,413	1,941
Payroll tax liability	2,810	1,816
Financing leases	1,834	1,499
Sale-leaseback liability[(c)]	3,340	1,290
Other	2,146	1,639
Total accrued expenses and other current liabilities	$ 62,516	$ 44,408
Other Long-Term Liabilities		
Financing leases	$ 4,375	4,618
Sale-leaseback liability[(c)]	7,318	3,348
Payroll tax liability	—	1,977
Other	—	492
Total other long-term liabilities	$ 11,693	$ 10,435

a. In June 2021, the Company reached an agreement to settle a certain legal matter. See Note 19 for additional detail.

b. Financed insurance premiums are due in monthly installments, are unsecured and mature within the twelve-month period following the close of the year. As of December 31, 2021, the applicable interest rates associated with financed insurance premiums ranged from 1.95% to 2.45%. As of December 31, 2020, the applicable interest rates associated with financed insurance premiums ranged from 3.45% to 3.75%.

c. On December 30, 2020, the Company entered into an agreement with First National Capital, LLC ("FNC") whereby the Company agreed to sell certain assets from its infrastructure segment to FNC for aggregate proceeds of $5.0 million. Concurrent with the sale of assets, the Company entered into a36 month lease agreement whereby the Company will lease back the assets at a monthly rental rate of $0.1 million. On June 1, 2021, the Company entered into another agreement with FNC whereby the Company sold additional assets from its infrastructure segment to FNC for aggregate proceeds of $9.5 million and entered into a 42 month lease agreement whereby the Company agreed to lease back the assets at a monthly rental rate of $0.2 million. Under the agreement, the Company has the option to purchase the assets at the end of the lease term. The Company recorded a liability for the proceeds received and will continue to depreciate the assets. The Company has imputed an interest rate so that the carrying amount of the financial liability will be the expected repurchase price at the end of the initial lease term.

10. Debt

Long-term debt included the following (in thousands):

	December 31,	
	2021	**2020**
Revolving credit facility	83,370	78,000
Aviation note	3,371	4,551
Unamortized debt issuance costs	(33)	(48)
Total debt	86,708	82,503
Less: current portion	1,468	1,165
Total long-term debt	$ 85,240	$ 81,338

Mammoth Credit Facility

On October 19, 2018, Mammoth Inc. and certain of its direct and indirect subsidiaries, as borrowers, entered into an amended and restated revolving credit and security agreement with the lenders party thereto and PNC Bank, National Association, as a lender and as administrative agent for the lenders, as amended and restated (the "revolving credit facility"). The revolving credit facility matures on October 19, 2023. Borrowings under the revolving credit facility are secured by the assets of Mammoth Inc., inclusive of the subsidiary companies, and are subject to a borrowing base calculation prepared monthly.

The revolving credit facility also contains various customary affirmative and restrictive covenants. Among the covenants is a financial covenant, including a minimum fixed charges coverage ratio of at least 1.1 to 1.0.

As a result of the lack of payment from PREPA, the Company projected that it would likely breach the leverage ratio covenant contained in its revolving credit facility for the fiscal quarter ended September 30, 2021. On November 3, 2021, the Company entered into a third amendment to its revolving credit facility (the "Third Amendment") to, among other things, (i) suspend the leverage ratio and fixed charges coverage ratio covenants for the quarters ending September 30, 2021 and December 31, 2021, (ii) permanently reduce the maximum revolving advance amount from $130 million to $120 million, (iii) add a minimum adjusted EBITDA financial covenant of $6.0 million for the quarter ending December 31, 2021, (iv) set the applicable margin on all loans at 3.50% during the limited covenant waiver period, (v) add a requirement to maintain revolver availability of not less than $10.0 million at all times during the limited covenant waiver period, (vi) permanently reduce the maximum revolving advance amount in an amount equal to fifty percent (50%) of any mandatory prepayments made with non-recurring proceeds that are received during the limited covenant waiver period, and (vii) eliminate the declaration of unrestricted subsidiaries during the limited covenant waiver period. The limited covenant waiver period commenced on the effective date of the Third Amendment and was scheduled to end on the earlier to occur of (i) May 15, 2022, (ii) the Company reporting compliance with both the leverage ratio and the fixed charge coverage ratio covenants for either its fiscal quarter ending September 30, 2021 or December 31, 2021, and (iii) the occurrence of any event of default after the effective date of the Third Amendment. Under the Third Amendment, the Company also agreed to engage an advisor during the limited covenant waiver period to advise the Company and its subsidiaries with regard to, among other things, efforts to achieve certain operation efficiencies, improvement in results of operations, and general business strategy, and provide assistance to the Company and its subsidiaries in the preparation of the supplemental reporting and information required by the Third Amendment.

At December 31, 2021, there were outstanding borrowings under the revolving credit facility of $83.4 million and $16.5 million of available borrowing capacity, after giving effect to $9.0 million of outstanding letters of credit and the requirement to maintain a $10 million reserve out of the available borrowing capacity during the limited waiver period. At December 31, 2020, there were outstanding borrowings under the revolving credit facility of $78.0 million and $38.7 million of borrowing capacity under the facility, after giving effect to $13.0 million of outstanding letters of credit. As of December 31, 2021, the Company was in compliance with its financial covenants under the revolving credit facility, as amended and waived by the Third Amendment.

On February 28, 2022, the Company entered into a fourth amendment to the revolving credit facility (the "Fourth Amendment") to, among other things, (i) amend the financial covenants as outlined below, (ii) provide for a conditional increase of the applicable interest margin, (iii) permit certain sale-leaseback transactions, (iv) provide for a reduction in the maximum revolving advance amount in an amount equal to 50% of the PREPA claims proceeds, subject to a floor equal to the sum of eligible billed and unbilled accounts receivables, and (v) classifies the payments pursuant to the Company's settlement agreement with MasTec Renewables Puerto Rico, LLC ("MasTec") as restricted payments and requires $20.0 million of availability both before and after making such payments.

The financial covenants under our revolving credit facility were amended as follows:

- the leverage ratio was eliminated;
- the fixed charge coverage ratio was reduced to .85 to 1.0 for the six months ended June 30, 2022 and increases to 1.1 to 1.0 for the periods thereafter;
- a minimum adjusted EBITDA covenant of $4.7 million, excluding interest on accounts receivable from PREPA, for the five months ending May 31, 2022 was added; and
- the minimum excess availability covenant was reduced to $7.5 million through the earlier of (i) March 31, 2022 or (ii) the date on which proceeds of permitted sale-leaseback transactions are received, after which the minimum excess availability covenant will increase to $10.0 million.

The Fourth Amendment also permanently waived compliance by the borrowers with the leverage ratio and fixed charge coverage ratio covenants in the revolving credit facility for the fiscal quarters ended September 30, 2021 and December 31, 2021, respectively, ending the limited covenant waiver period under the Third Amendment.

As of March 2, 2022, the Company had $83.7 million in borrowings outstanding under its revolving credit facility, leaving an aggregate of $10.6 million of available borrowing capacity under this facility, after giving effect to $8.5 million of outstanding letters of credit and the requirement to maintain a $7.5 million reserve out of the available borrowing capacity.

If an event of default occurs under the revolving credit facility and remains uncured, it could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows. The lenders (i) would not be required to lend any additional amounts to the Company, (ii) could elect to increase the interest rate by 200 basis points, (iii) could elect to declare all outstanding borrowings, together with accrued and unpaid interest and fees, to be due and payable, (iv) may have the ability to require the Company to apply all of its available cash to repay outstanding borrowings, and (v) may foreclose on substantially all of the Company's assets. As of March 2, 2022, the Company was in compliance with the covenants under its revolving credit facility, as amended and waived by the Third Amendment and Fourth Amendment.

Aviation Note

On November 6, 2020, Leopard and Cobra Aviation entered into a 39 month promissory note agreement with Bank7 (the "Aviation Note") in an aggregate principal amount of $4.6 million and received net proceeds of $4.5 million. The Aviation Note bears interest at a rate based on the Wall Street Journal Prime Rate plus a margin of 1%. Principal and interest payments of $0.1 million are due monthly, with a final payment of $0.2 million due on February 1, 2024. The Aviation Note is collateralized by Leopard and Cobra Aviation's assets, including a $1.8 million certificate of deposit. The Aviation Note contains various customary affirmative and restrictive covenants, all of which the Company was in compliance with as of December 31, 2021.

As of December 31, 2021, the Company did not meet the minimum debt coverage ratio of 1.25 to 1.0 set forth in the Aviation Note. On March 2, 2022, Bank7 granted the Company a waiver of this event of default. The waiver extended the minimum cash requirement until June 30, 2022.

11. Variable Interest Entities

Dire Wolf and Predator Aviation, wholly owned subsidiaries of the Company, are party to Voting Trust Agreements with TVPX Aircraft Solutions Inc. (the "Voting Trustee"). Under the Voting Trust Agreements, Dire Wolf transferred 100% of its membership interest in Cobra Aviation and Predator Aviation transferred100% of its membership interest in Leopard to the respective Voting Trustees in exchange for Voting Trust Certificates. Dire Wolf and Predator Aviation retained the obligation to absorb all expected returns or losses of Cobra Aviation and Leopard. Prior to the transfer of the membership interest to the Voting Trustee, Cobra Aviation was a wholly owned subsidiary of Dire Wolf and Leopard was a wholly owned subsidiary of Predator Aviation. Cobra Aviation owns two helicopters and support equipment, 100% of the equity interest in ARS and 49% of the equity interest in Brim Acquisitions. Leopard ownsone helicopter. Dire Wolf and Predator Aviation entered into the Voting Trust Agreements in order to meet certain registration requirements.

Dire Wolf's and Predator Aviation's voting rights are not proportional to their respective obligations to absorb expected returns or losses of Cobra Aviation and Leopard, respectively, and all of Cobra Aviation's and Leopard's activities are conducted on behalf of Dire Wolf and Predator Aviation, which have disproportionately fewer voting rights; therefore, Cobra Aviation and Leopard meet the criteria of a VIE. Cobra Aviation and Leopard's operational activities are directed by Dire Wolf's and Predator Aviation's officers and Dire Wolf and Predator Aviation have the option to terminate the Voting Trust Agreements at any time. Therefore, the Company, through Dire Wolf and Predator Aviation, is considered the primary beneficiary of the VIEs and consolidates Cobra Aviation and Leopard at December 31, 2021.

12. Selling, General and Administrative Expense

Selling, general and administrative ("SG&A") expense includes of the following (in thousands):

		Years Ended December 31,		
		2021	2020	2019
Cash expenses:				
Compensation and benefits	$	15,064	14,876	19,364
Professional services		11,400	19,905	17,128
Other[(a)]		9,052	8,828	10,300
Total cash SG&A expense		35,516	43,609	46,792
Non-cash expenses:				
Bad debt provision[(b)]		41,662	21,958	1,434
Stock based compensation		1,068	1,618	3,326
Total non-cash SG&A expense		42,730	23,576	4,760
Total SG&A expense	$	78,246	67,185	51,552

a. Includes travel-related costs, information technology expenses, rent, utilities and other general and administrative-related costs.

b. The bad debt provision for the year ended December 31, 2021 includes $ 41.2 million related to the Stingray Pressure Pumping and Muskie contracts with Gulfport. The bad debt provision for the year ended December 31, 2020, included $19.4 million related to the voluntary petitions for relief filed on November 13, 2020, by Gulfport and certain of its subsidiaries. See Notes 2 and 19.

13. Income Taxes

The components of income tax benefit attributable to the Company for the year ended December 31, 2021, 2020 and 2019, respectively, are as follows (in thousands):

	Year Ended December 31,					
	2021		2020		2019	
U.S. current income tax expense (benefit)	$	290	$	(6,931)	$	386
U.S. deferred income tax benefit		(23,740)		(12,330)		(21,761)
Foreign current income tax expense		8,852		6,948		30,172
Foreign deferred income tax (benefit) expense		(8,265)		144		(20,878)
Total	$	(22,863)	$	(12,169)	$	(12,081)

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Loss before income taxes	$ (124,293)	$ (119,776)	$ (91,125)
Statutory income tax rate	21 %	21 %	21 %
Expected income tax (benefit) expense	(26,102)	(25,153)	(19,136)
Change in tax rate	—	(161)	—
Change in uncertain tax positions	1,043	—	—
Foreign income tax rate differential	(282)	2,556	9,387
Foreign (loss) earnings not in reported income	(336)	3,252	12,581
Foreign tax credits	(7,749)	(7,133)	(26,141)
Withholding taxes	(49)	1,019	3,635
Goodwill impairment	52	11,544	6,506
Other permanent differences	426	1,290	1,873
State tax expenses	(2,449)	(1,664)	2,364
CARES act	—	(2,378)	—
Return to provision	390	894	(15,156)
Change in valuation allowance	12,193	3,765	12,006
Total	$ (22,863)	$ (12,169)	$ (12,081)

The Company’s effective tax rate was 18.4% for the year ended December 31, 2021 compared to 10.2% for the year ended December 31, 2020 and 13.3% for the year ended December 31, 2019.

The effective tax rate for the year ended December 31, 2021 differed from the statutory rate of 21% primarily due to the mix of earnings between the United States and Puerto Rico as well as changes in the valuation allowance. Additionally, the Company recorded an unrecognized tax benefit of $1.0 million during the year ended December 31, 2021 related to the 2020 tax year returns in Puerto Rico.

On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security (CARES) Act was enacted and signed into U.S. law in response to the COVID-19 pandemic, and among other things, permits the carryback of certain net operating losses. As a result of the enacted legislation, the Company recognized a $2.4 million net tax benefit during the year ended December 31, 2020, which consisted of a $7.0 million current tax benefit and a $4.6 million deferred tax expense. This impact, along with the rate impact from non-deductible goodwill impairment and the change in valuation allowance, was the primary driver for the difference between the statutory rate of 21% and the effective tax rate for the years ended December 31, 2020.

The effective tax rate for the year ended December 31, 2019 differed from the statutory rate of 21% primarily due to the mix of earnings between the United States and Puerto Rico. For the year ended December 31, 2019, the Company recognized a loss in the United States, which was partially offset by earnings from its operations in Puerto Rico, which has a higher statutory rate compared to the United States. Additionally, during the year ended December 31, 2019, the Company recorded a benefit related to return to provision adjustments, which was partially offset by changes in the valuation allowance.

Deferred tax liabilities attributable to the Company consisted of the following (in thousands):

	Year Ended December 31,	
	2021	2020
Deferred tax assets:		
Allowance for doubtful accounts	$ 1,241	$ 1,541
Lease asset	4,432	6,060
Intangible assets	1,070	—
Accrued liabilities	12,833	740
Net operating loss carryover	13,447	613
Foreign tax credits	83,780	80,615
Other	1,652	1,919
Valuation allowance	(71,612)	(67,888)
Deferred tax assets	46,843	23,600
Deferred tax liabilities:		
Property and equipment	$ (28,126)	$ (39,057)
Intangible assets	—	(450)
Lease liability	(4,392)	(6,030)
Other	(7,096)	(2,804)
Deferred tax liabilities	(39,614)	(48,341)
Net deferred tax asset (liability)	$ 7,229	$ (24,741)
Reflected in accompanying balance sheet as:		
Deferred income tax asset	$ 8,094	$ —
Deferred income tax liability	(865)	(24,741)
Total	$ 7,229	$ (24,741)

During the years ended December 31, 2021 and 2020, the Company recorded changes in its valuation allowance of $12.2 million and $3.8 million, respectively, related to excess foreign tax credits that are not expected to be utilized. The Company has foreign tax credits carryforwards of $83.8 million as of December 31, 2021. These credits have a 10 year carryforward period and begin to expire in 2028.

The Company maintains a partial valuation allowance related to U.S. foreign tax credit carryforwards, as it cannot objectively assert that these deferred tax assets are more likely than not to be realized. All available positive and negative evidence was weighed to determine whether a valuation allowance was necessary. The more significant evidential matter is the higher foreign tax rate applied to foreign source income in comparison to the U.S. Federal tax rate of 21%. As a result, the Company's has foreign tax credits in excess of the corresponding U.S. income tax liability for which the foreign tax credits are allowed as an offset and, therefore, are not likely to be realized.

At December 31, 2021, the Company had undistributed earnings in its Puerto Rico foreign branch. The distribution of these undistributed earnings is subject to a withholding tax in Puerto Rico and since the Company intends to make these distributions in the future, the withholding tax has been accrued.

A reconciliation of the beginning and ending amounts of liabilities associated with uncertain tax positions for the year ended December 31, 2021 is as follows ($ in thousands):

Balance, January 1, 2021	$ —
Additions for tax positions of prior years	1,043
Balance, December 31, 2021	$ 1,043

The Company recorded an unrecognized tax benefit of $1.0 million during the year ended December 31, 2021 related to the 2020 tax year returns in Puerto Rico. It is the Company's policy to recognize interest and applicable penalties related to uncertain tax positions in income tax expense. The Company did not have any uncertain tax positions for the years ended December 31, 2020 and 2019.

The Company's U.S. federal tax returns for tax years 2017 through 2021 remain subject to examination by the tax authorities. The Company's state and local income tax returns for tax years 2016 through 2021 remain subject to examination, with few exceptions, by the respective tax authorities. Puerto Rico tax returns for tax years 2017 through 2021 and Canada tax returns for the tax years 2015 through 2021 remain open to examination by the respective tax authorities.

14. Leases

Lessee Accounting

The Company recognized a lease liability equal to the present value of the lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for all leases with a term in excess of 12 months. For operating leases, lease expense for lease payments is recognized on a straight-line basis over the lease term, while finance leases include both an operating expense and an interest expense component. For all leases with a term of 12 months or less, the Company has elected the practical expedient to not recognize lease assets and liabilities and recognizes lease expense for these short-term leases on a straight-line basis over the lease term.

The Company's operating leases are primarily for rail cars, real estate, and equipment and its finance leases are primarily for machinery and equipment. Generally, the Company does not include renewal or termination options in its assessment of the leases unless extension or termination for certain assets is deemed to be reasonably certain. The accounting for some of the Company's leases may require significant judgment, which includes determining whether a contract contains a lease, determining the incremental borrowing rates to utilize in the net present value calculation of lease payments for lease agreements which do not provide an implicit rate and assessing the likelihood of renewal or termination options. Lease agreements that contain a lease and non-lease component are generally accounted for as a single lease component.

The rate implicit in the Company's leases is not readily determinable. Therefore, the Company uses its incremental borrowing rate based on information available at the commencement date of its leases in determining the present value of lease payments. The Company's incremental borrowing rate reflects the estimated rate of interest that it would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment.

Lease expense consisted of the following for the years ended December 31, 2021 and 2020 (in thousands):

	Year Ended December 31,	
	2021	**2020**
Operating lease expense	$ 9,156	$ 13,735
Short-term lease expense	335	812
Finance lease expense:		
Amortization of right-of-use assets	1,582	1,311
Interest on lease liabilities	202	203
Total lease expense	$ 11,275	$ 16,061

Supplemental balance sheet information related to leases as of December 31, 2021 and 2020 is as follows (in thousands):

	Year Ended December 31, 2021	2020
Operating leases:		
Operating lease right-of-use assets	$ 12,168	$ 20,179
Current operating lease liability	5,942	8,618
Long-term operating lease liability	5,918	11,377
Finance leases:		
Property and equipment, net	$ 6,065	$ 6,065
Accrued expenses and other current liabilities	1,834	1,499
Other liabilities	4,375	4,618

Other supplemental information related to leases for the years ended December 31, 2021 and 2020 is as follows (in thousands):

	Year Ended December 31, 2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 9,284	$ 13,643
Operating cash flows from finance leases	202	203
Financing cash flows from finance leases	1,677	1,318
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 594	$ (10,260)
Finance leases	1,750	2,431

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	Year Ended December 31, 2021	2020
Weighted-average remaining lease term:		
Operating leases	3.1 years	3.2 years
Finance leases	3.3 years	4.2 years
Weighted-average discount rate:		
Operating leases	3.3 %	3.5 %
Finance leases	3.3 %	3.5 %

Maturities of lease liabilities as of December 31, 2021 are as follows (in thousands):

	Operating Leases	Finance Leases
2022	$ 6,214	$ 2,005
2023	3,600	2,261
2024	1,641	965
2025	517	524
2026	147	795
Thereafter	407	—
Total lease payments	12,526	6,550
Less: Present value discount	666	341
Present value of lease payments	$ 11,860	$ 6,209

Lessor Accounting

Certain of the Company’s agreements with its customers for drilling services, aviation services and remote accommodation services contain an operating lease component under ASC 842 because (i) there are identified assets, (ii) the customer obtains substantially all of the economic benefits of the identified assets throughout the period of use and (iii) the customer directs the use of the identified assets throughout the period of use. The Company has elected to apply the practical expedient provided to lessors to combine the lease and non-lease components of a contract where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The practical expedient also allows a lessor to account for the combined lease and non-lease components under ASC 606, *Revenue from Contracts with Customers*, when the non-lease component is the predominant element of the combined component.

The Company’s lease agreements are generally short-term in nature and lease revenue is recognized over time based on a monthly, daily or hourly rate basis. The Company does not provide an option for the lessee to purchase the rented assets at the end of the lease and the lessees do not provide residual value guarantees on the rented assets. During the years ended December 31, 2021, 2020 and 2019, the Company recognized lease revenue, which is included in “services revenue” and “services revenue - related parties” on the consolidated statements of comprehensive loss of $2.4 million, $1.4 million, and $2.3 million, respectively.

15. Dividends and Earnings (Loss) Per Share

Dividends

On July 16, 2018, the Company initiated a quarterly dividend policy. As a result of oilfield market conditions and other factors, which include collections from PREPA, the Company’s Board of Directors suspended the quarterly cash dividend in the third quarter of 2019. The table below summarizes the dividends paid on the Company’s common stock.

	Per Share	Total
		(in thousands)
2019		
Paid on February 14, 2019	$ 0.125	$ 5,609
Paid on May 17, 2019	0.125	5,610
Total cash dividends	$ 0.25	$ 11,219

Earnings (Loss) Per Share

	Year Ended December 31,		
	2021	2020	2019
			(in thousands, except per share data)
Basic loss per share:			
Allocation of earnings:			
Net loss	$ (101,430)	$ (107,607)	$ (79,044)
Weighted average common shares outstanding	46,428	45,644	45,011
Basic loss per share	$ (2.18)	$ (2.36)	$ (1.76)
Diluted loss per share:			
Allocation of earnings:			
Net loss	$ (101,430)	$ (107,607)	$ (79,044)
Weighted average common shares, including dilutive effect [a]	46,428	45,644	45,011
Diluted loss per share	$ (2.18)	$ (2.36)	$ (1.76)

a. No incremental shares of potentially dilutive restricted stock awards were included for the years ended December 31, 2021, 2020, or 2019 as their effect was antidilutive under the treasury stock method.

16. Equity Based Compensation

Upon formation of certain operating entities by Wexford, Gulfport and Rhino, specified members of management (the "Specified Members") and certain non-employee members (the "Non-Employee Members") were granted the right to receive distributions from the operating entities after the contribution member's unreturned capital balance was recovered (referred to as "Payout" provision).

On November 24, 2014, the awards were modified in conjunction with the contribution of the operating entities to Mammoth Inc. These awards were not granted in limited or general partner units. The awards are for interests in the distributable earnings of the members of MEH Sub, Mammoth Inc.'s majority equity holder.

On the closing date of Mammoth Inc.'s initial public offering ("IPO"), the unreturned capital balance of Mammoth's majority equity holder was not fully recovered from its sale of common stock in the IPO. As a result, Payout did not occur and no compensation cost was recorded.

Payout for the remaining awards is expected to occur as the contribution member's unreturned capital balance is recovered from additional sales by MEH Sub of its shares of the Company's common stock or from dividend distributions, which is not considered probable until the event occurs. For the Specified Member awards, the unrecognized amount, which represents the fair value of the award as of the modification dates or grant date, was $5.6 million.

For the Company's Non-Employee Member awards, the unrecognized amount, which represents the fair value of the awards as of the date of adoption of ASU 2018-07 was $18.9 million.

17. Stock-Based Compensation

The 2016 Plan authorizes the Company's Board of Directors or the compensation committee of the Company's Board of Directors to grant restricted stock, restricted stock units, stock appreciation rights, stock options and performance awards. There are 4.5 million shares of common stock reserved for issuance under the 2016 Plan.

Restricted Stock Units

The fair value of restricted stock unit awards was determined based on the fair market value of the Company's common stock on the date of the grant. This value is amortized over the vesting period. Forfeitures are recognized as incurred.

A summary of the status and changes of the unvested shares of restricted stock under the 2016 Plan is presented below.

	Number of Unvested Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested restricted stock units as of January 1, 2019	434,119	$ 22.78
Granted	101,181	6.83
Vested	(231,896)	22.45
Forfeited	(82,163)	18.55
Unvested restricted stock units as of December 31, 2019	221,241	22.43
Granted	2,401,446	0.98
Vested	(660,738)	5.32
Forfeited	(47,167)	3.28
Unvested restricted stock units as of December 31, 2020	1,914,782	1.21
Granted	128,205	3.90
Vested	(914,782)	1.52
Forfeited	—	—
Unvested restricted stock units as of December 31, 2021	1,128,205	1.27

As of December 31, 2021, there was $0.8 million of total unrecognized compensation cost related to the unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately 1.0 year.

Included in cost of revenue and selling, general and administrative expenses is stock-based compensation expense of $1.2 million, $2.0 million and $4.2 million, respectively, for the years ended December 31, 2021, 2020 and 2019.

18. Related Party Transactions

Transactions between the subsidiaries of the Company and the following companies are included in Related Party Transactions: Wexford, Gulfport; Grizzly Oil Sands ULC ("Grizzly"); El Toro Resources LLC ("El Toro"); Everest Operations Management LLC ("Everest"); Elk City Yard LLC ("Elk City Yard"); Double Barrel Downhole Technologies LLC ("DBDHT"); Caliber Investment Group LLC ("Caliber"); Predator Drilling LLC ("Predator"); and Brim Equipment.

Following is a summary of related party transactions (in thousands):

		Years Ended December 31,			At December 31,	
		2021	2020	2019	2021	2020
		REVENUES			ACCOUNTS RECEIVABLE	
Stingray Pressure Pumping and Gulfport	(a)	$ 14,812	$ 42,460	$ 90,357	$ —	$ 25,429
Muskie and Gulfport	(b)	2,145	7,500	27,689	—	1,127
SR Energy and Gulfport	(c)	—	113	8,772	—	8
Aquahawk and Gulfport	(d)	—	—	828	—	—
Cobra Aviation/ARS/Leopard and Brim Equipment	(e)	371	446	2,093	85	44
Panther and El Toro	(f)	599	38	573	—	—
Other Relationships		12	34	1	3	9
		$ 17,939	$ 50,591	$ 130,313	$ 88	$ 26,617
		OTHER			ACCOUNTS RECEIVABLE	
Stingray Pressure Pumping and Gulfport	(a)	$ 514	$ 1,887	$ —	$ —	$ 1,841
Muskie and Gulfport	(b)	1	3	—	—	3
		$ 515	$ 1,890	$ —	$ —	$ 1,844
					$ 88	$ 28,461

a. Stingray Pressure Pumping provided pressure pumping, stimulation and related completion services to Gulfport. Other amount represents interest charged on delinquent accounts receivable related to these services. On June 29, 2021, Gulfport ceased to be a related party. See Note 3.
b. Muskie agreed to sell and deliver, and Gulfport has agreed to purchase, specified annual and monthly amounts of natural sand proppant, subject to certain exceptions specified in the agreement, and pay certain costs and expenses. Other amount represents interest charged on delinquent accounts receivable related to this agreement. On June 29, 2021, Gulfport ceased to be a related party. See Note 3.
c. SR Energy provided rental services for Gulfport. On June 29, 2021, Gulfport ceased to be a related party.
d. Aquahawk provided water transfer services for Gulfport pursuant to a master services agreement.
e. Cobra Aviation, ARS and Leopard lease helicopters to Brim Equipment pursuant to aircraft lease and management agreements.
f. Panther provides directional drilling services for El Toro, an affiliate of Wexford, pursuant to a master service agreement.

		COST OF REVENUE			ACCOUNTS PAYABLE	
		Years Ended December 31,			At December 31,	
		2021	2020	2019	2021	2020
Cobra Aviation/ARS/Leopard and Brim Equipment	(a)	73	72	4,720	5	
The Company and Caliber	(b)	351	248	—	—	
Other Relationships		107	98	50	—	
		$ 531	$ 418	$ 4,770	$ 5	$
		SELLING, GENERAL AND ADMINISTRATIVE COSTS				
The Company and Wexford	(c)	5	3	650	—	
The Company and Caliber	(b)	374	774	785	—	
Cobra Aviation/ARS/Leopard and Brim Equipment	(a)	—	—	233		
Other Relationships		8	(19)	179	—	
		$ 387	$ 758	$ 1,847	$ —	$
		CAPITAL EXPENDITURES				
Leopard and Brim Equipment	(a)	—	—	420	—	
		$ —	$ —	$ 420	$ —	$
					$ 5	$

a. Cobra Aviation, ARS and Leopard lease helicopters to Brim Equipment pursuant to aircraft lease and management agreements.
b. Caliber, an entity controlled by Wexford, leases office space to the Company.
c. Wexford provides certain administrative and analytical services to the Company and, from time to time, the Company pays for goods and services on behalf of Wexford.

On December 21, 2018, Cobra Aviation acquired all outstanding equity interest in ARS and purchased two commercial helicopters, spare parts, support equipment and aircraft documents from Brim Equipment. Following these transactions, and also on December 21, 2018, Cobra Aviation formed a joint venture with Wexford Investments named Brim Acquisitions to acquire all outstanding equity interests in Brim Equipment. Cobra Aviation owns a 49% economic interest and Wexford Investment owns a 51% economic interest in Brim Acquisitions, and each member contributed its pro rata portion of Brim Acquisitions' initial capital of $2.0 million. Cobra Aviation made additional investments in Brim Acquisitions totaling $0.5 million and $0.7 million during the years ended December 31, 2020 and 2019, respectively. Wexford Investments is an entity controlled by Wexford, which owns approximately 48% of the Company's outstanding common stock. ARS leases a helicopter to Brim Equipment and Cobra Aviation leases the two helicopters purchased as part of these transactions to Brim Equipment under the terms of aircraft lease and management agreements. See Note 8 for further discussion.

19. Commitments and Contingencies

Commitments

The Company has entered into agreements with suppliers that contain minimum purchase obligations and agreements to purchase capital equipment. Aggregate future minimum payments under these obligations in effect at December 31, 2021 were approximately $1.4 million.

Letters of Credit

The Company has various letters of credit that were issued under the Company's revolving credit facility which is collateralized by substantially all of the assets of the Company. The letters of credit are categorized below (in thousands):

	December 31,	
	2021	2020
Bonding program	$ 1,000	$ 5,000
Environmental remediation	3,694	3,694
Insurance programs	3,890	3,890
Rail car commitments	455	455
Total letters of credit	$ 9,039	$ 13,039

Insurance

The Company has insurance coverage for physical partial loss to its assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. The Company has also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. As of December 31, 2021 and 2020, the workers' compensation and automobile liability policies required a deductible per occurrence of up to $0.3 million and $0.1 million, respectively. The Company establishes liabilities for the unpaid deductible portion of claims incurred based on estimates. As of December 31, 2021 and 2020, the workers' compensation and auto liability policies contained an aggregate stop loss of $5.4 million. The Company establishes liabilities for the unpaid deductible portion of claims incurred relating to workers' compensation and auto liability based on estimates. As of December 31, 2021 and 2020, accrued claims were $1.4 million and $1.9 million, respectively.

The Company also has insurance coverage for directors and officers liability. As of December 31, 2021 and 2020, the directors and officers liability policy had a deductible per occurrence of $1.0 million and an aggregate deductible of $10.0 million. As of December 31, 2021 and 2020, the Company did not have any accrued claims for directors and officers liability.

The Company also self-insures its employee health insurance. The Company has coverage on its self-insurance program in the form of a stop loss of $0.2 million per participant and an aggregate stop-loss of $5.8 million for the calendar year ending December 31, 2021. As of December 31, 2021 and 2020, accrued claims were $1.6 million and $1.3 million, respectively. These estimates may change in the near term as actual claims continue to develop.

Warranty Guarantees

Pursuant to certain customer contracts in our infrastructure services segment, the Company warrants equipment and labor performed under the contracts for a specified period following substantial completion of the work. Generally, the warranty is for one year or less. No liabilities were accrued as of December 31, 2021 or 2020 andno expense was recognized during the years ended December 31, 2021, 2020 or 2019 related to warranty claims. However, if warranty claims occur, the Company could be required to repair or replace warrantied items, which in most cases are covered by warranties extended from the manufacturer of the equipment. In the event the manufacturer of equipment failed to perform on a warranty obligation or denied a warranty claim made by the Company, the Company could be required to pay for the cost of the repair or replacement.

Bonds

In the ordinary course of business, the Company is required to provide bid bonds to certain customers in the infrastructure services segment as part of the bidding process. These bonds provide a guarantee to the customer that the Company, if awarded the project, will perform under the terms of the contract. Bid bonds are typically provided for a percentage of the total contract value. Additionally, the Company may be required to provide performance and payment bonds for contractual commitments related to projects in process. These bonds provide a guarantee to the customer that the Company will perform under the terms of a contract and that the Company will pay subcontractors and vendors. If the Company fails to perform under a contract or to pay subcontractors and vendors, the customer may demand that the surety make payments or provide services under the bond. The Company must reimburse the surety for expenses or outlays it incurs. As of December 31, 2021 and 2020, outstanding performance and payment bonds totaled $20.3 million and $18.1 million, respectively. The estimated cost to complete projects secured by the performance and payment bonds totaled $4.7 million as of December 31, 2021. As of December 31, 2021 and 2020, outstanding bid bonds totaled $0.6 million and $1.0 million, respectively.

Litigation

As of December 31, 2021, PREPA owed the Company approximately $227.0 million for services performed, excluding $110.8 million of interest charged on these delinquent balances as of December 31, 2021. The Company believes these receivables are collectible. PREPA, however, is currently subject to bankruptcy proceedings, which were filed in July 2017 and are currently pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPA's ability to meet its payment obligations is largely dependent upon funding from FEMA or other sources. On September 30, 2019, Cobra filed a motion with the U.S. District Court for the District of Puerto Rico seeking recovery of the amounts owed to Cobra by PREPA, which motion was stayed by the Court. On March 25, 2020, Cobra filed an urgent motion to modify the stay order and allow the recovery of approximately $61.7 million in claims related to a tax gross-up provision contained in the emergency master service agreement, as amended, that was entered into with PREPA on October 19, 2017. This emergency motion was denied on June 3, 2020 and the Court extended the stay of our motion. On December 9, 2020, the Court again extended the stay of our motion and directed PREPA to file a status motion by June 7, 2021. On April 6, 2021, Cobra filed a motion to lift the stay order. Following this filing, PREPA initiated discussion, which resulted in PREPA and Cobra filing a joint motion to adjourn all deadlines relative to the April 6, 2021 motion until the June 16, 2021 omnibus hearing as a result of PREPA's understanding that FEMA would release a report in the near future relating to the emergency master service agreement between PREPA and Cobra that was executed on October 19, 2017. The joint motion was granted by the Court on April 14, 2021. On May 26, 2021, FEMA issued a Determination Memorandum related to the first contract between Cobra and PREPA in which, among other things, FEMA raised two contract compliance issues and, as a result, concluded that approximately $47 million in costs were not authorized costs under the contract. On June 14, 2021, the Court issued an order adjourning Cobra's motion to lift the stay order to a hearing on August 4, 2021 and directing Cobra and PREPA to meet and confer in good faith concerning, among other things, (i) the May 26, 2021 Determination Memorandum issued by FEMA and (ii) whether and when a second determination memorandum is expected. The parties were further directed to file an additional status report, which was filed on July 20, 2021. On July 23, 2021, with the aid of Mammoth, PREPA filed an appeal of the entire $47 million that FEMA de-obligated in the May 26, 2021 Determination Memorandum. On August 4, 2021, the Court extended the stay and directed that an additional status report be filed, which was done on January 22, 2022. On January 26, 2022, the Court extended the stay and directed the parties to file a further status report by July 25, 2022. In the event PREPA (i) does not have or does not obtain the funds necessary to satisfy its obligations to Cobra under the contracts, (ii) obtains the necessary funds but refuses to pay the amounts owed to the Company or (iii) otherwise does not pay amounts owed to the Company for services performed, the receivable may not be collectible.

On December 28, 2019, Gulfport filed a lawsuit against Stingray Pressure Pumping in the Superior Court of the State of Delaware. Pursuant to the complaint, Gulfport sought to terminate the October 1, 2014, Amended and Restated Master Services Agreement for Pressure Pumping Services between Gulfport and Stingray Pressure Pumping ("MSA"). In addition, Gulfport alleged breach of contract and sought damages for alleged overpayments and audit costs under the MSA and other fees and expenses associated with this lawsuit. On March 26, 2020, Stingray Pressure Pumping filed a counterclaim against Gulfport seeking to recover unpaid fees and expenses due to Stingray Pressure Pumping under the MSA. In September 2020, Muskie filed a lawsuit against Gulfport to recover delinquent payments due under a natural sand proppant supply contract. These matters were automatically stayed as a result of Gulfport's bankruptcy filing on November 13, 2020, seeking voluntary relief under chapter 11 of the Bankruptcy Code. Gulfport emerged from bankruptcy on May 17, 2021. As of November 13, 2020, Gulfport owed the Company approximately $46.9 million, which included interest charges of $3.3 million and $1.8 million in attorneys' fees. FASB ASC 326, *Financial Instruments-Credit Losses,* requires companies to reflect its current estimate of all expected credit losses. As a result, the Company recorded reserves on its pre-petition receivables due from Gulfport for products and services, interest and attorneys' fees of $19.4 million, $1.4 million and $1.8 million, respectively, during the year ended December 31, 2020. On March 22, 2021, Gulfport listed the Stingray Pressure Pumping and Muskie contracts on its master rejection schedule filed with the bankruptcy court. During the first quarter of 2021, the Company recognized unliquidated damages of approximately $46.4 million and recorded reserves on these unliquidated damages as a reduction to revenue of $27.1 million and to bad debt expense of $3.8 million. Also during the first quarter of 2021, the Company recorded additional reserves on its pre-petition products and services and interest receivables of $6.1 million and $0.5 million, respectively. On September 21, 2021, the Company and Gulfport reached a settlement under which all litigation relating to the Stingray Pressure Pumping contract and the Muskie contract was terminated, Stingray Pressure Pumping released all claims against Gulfport and its subsidiaries with respect to Gulfport's bankruptcy proceedings, each of the parties released all claims they had against the others with respect to the litigation matters discussed above and Muskie retained an allowed general unsecured claim against Gulfport of $3.1 million. As a result, during the three months ended September 30, 2021, the Company wrote off its remaining receivable related to the Stingray Pressure Pumping claim resulting in bad debt expense and other expense of $31.0 million and $1.3 million, respectively, and recorded additional bad debt expense related to the Muskie claim totaling $0.2 million. The Company had net accounts receivable due from Gulfport totaling $0.1 million as of December 31, 2021, which is included in “accounts receivable, net” on the balance sheets.

On January 21, 2020, MasTec Renewables Puerto Rico, LLC (“MasTec”) filed a lawsuit against Mammoth Inc. and Cobra in the U.S. District Court for the Southern District of Florida. MasTec’s complaint asserted claims against the Company and Cobra Acquisitions for violations of the federal Racketeer Influenced and Corrupt Organizations Act (“RICO”), tortious interference and violations of Puerto Rico law. MasTec alleged that it sustained injuries to its business and property in an unspecified amount because it lost the opportunity to perform work in connection with rebuilding the energy infrastructure in Puerto Rico after Hurricane Maria under a services contract with a maximum value of $500 million due to the Company’s and Cobra’s wrongful interference, payment of bribes, and other inducement to a FEMA official. On April 1, 2020, the defendants filed a motion to dismiss the complaint. On October 14, 2020, the Court dismissed the RICO claims, and on November 18, 2020, dismissed the claims arising under the Puerto Rico statute and the cause of action for tortious interference with MasTec’s contract (but not its business relations), and dismissed Mammoth Inc. from the litigation. On August 2, 2021, in order to avoid the risks of further litigation, and with no admission of wrongdoing whatsoever, the Company reached an agreement to settle this matter. Under the terms of the agreement, Cobra paid $6.5 million to MasTec on August 2, 2021 and the Company guaranteed payment, by Cobra, of $9.25 million on both August 1, 2022 and December 1, 2022. The agreement bears interest at rates between 6% and 12% and includes an acceleration clause that requires Cobra to pay withinten days all unpaid amounts if Cobra collects $100 million or more of specified receivables. The settlement amount and legal expenses related to the matter of $25.0 million and $5.4 million, respectively, are reflected in “other, net” on the accompanying consolidated statement of comprehensive loss for the year ended December 31, 2021. As of December 31, 2021, $19.0 million was included in “accrued expenses and other current liabilities” in the accompanying consolidated balance sheets, which includes accrued interest of $0.5 million.

On May 13, 2021, Foreman Electric Services, Inc. (“Foreman”) filed a petition against Mammoth Inc. and Cobra in the Oklahoma County District Court (Oklahoma State Court). The petition asserted claims against the Company and Cobra under federal RICO statutes and certain state-law causes of action. Foreman alleged that it sustained injuries to its business and property in the amount of $250 million due to the Company’s and Cobra’s wrongful interference, payment of bribes and other inducements to a FEMA official. On May 18, 2021, the Company removed this action to the United States District Court for the Western District of Oklahoma and filed a motion to dismiss on July 8, 2021. On July 29, 2021, Foreman voluntarily dismissed the action without prejudice. On December 14, 2021, Foreman re-filed its petition against Mammoth Inc. and Cobra in the Oklahoma Count District Court (Oklahoma State Court). On December 16, 2021, the Company again removed this action to the United States District Court for the Western District of Oklahoma. Foreman filed a motion to remand this action back to Oklahoma County District Court, which motion is under consideration by the federal court. The Company and Cobra filed a motion to dismiss on January 31, 2022, which is expected to be fully briefed by March 7, 2022. In a related matter, on January 12, 2022, a Derivative Complaint on behalf of nominal defendant Machine Learning Integration, LLC (“MLI”), which alleges it would have served as a sub-contractor to Foreman in Puerto Rico, was filed against the Company and Cobra in the U.S. District Court for the District of Puerto Rico arising from essentially the same facts as Foreman's action and asserting violations of federal RICO statutes and certain state law claims. MLI alleges it sustained injuries to its business and property in an unspecified amount because the Company’s and Cobra’s wrongful interference, payment of bribes and other inducements to a FEMA official prevented Foreman from obtaining work, and thereby prevented MLI, as Foreman's subcontractor, from obtaining work. These matters are still in the early stages and at this time, the Company is not able to predict the outcome of these claims or whether they will have a material impact on the Company’s business, financial condition, results of operations or cash flows.

The Company is routinely involved in state and local tax audits. During 2015, the State of Ohio assessed taxes on the purchase of equipment the Company believes is exempt under state law. The Company appealed the assessment and a hearing was held in 2017. As a result of the hearing, the Company received a decision from the State of Ohio, which the Company appealed. On February 25, 2022, the Company received an unfavorable decision on the appeal. The Company intends to appeal the decision and while it is not able to predict the outcome of the appeal, this matter is not expected to have a material adverse effect on the Company’s business, financial condition, results of operations or cash flows.

On June 19, 2018, Wendco of Puerto Rico Inc. filed a putative class action lawsuit in the Commonwealth of Puerto Rico styled Wendco of Puerto Rico Inc.; Multisystem Restaurant Inc.; Restaurant Operators Inc.; Apple Caribe, Inc.; on their own behalf and in representation of all businesses that conduct business in the Commonwealth of Puerto Rico vs. Mammoth Energy Services Inc.; Cobra Acquisitions LLC; D. Grimm Puerto Rico, LLC, et al. The plaintiffs allege that the defendants caused power outages in Puerto Rico while performing restoration work on Puerto Rico’s electrical network following Hurricanes Irma and Maria in 2017, thereby interrupting commercial activities and causing economic loss. The parties have agreed to a settlement in principle and are in the process of documenting the settlement. Until the settlement agreement is executed, however, the Company is not able to predict the outcome of this lawsuit or whether it will have a material impact on the Company's business, financial condition, results of operations or cash flows.

Cobra has been served with ten lawsuits from municipalities in Puerto Rico alleging failure to pay construction excise and volume of business taxes. These matters are in various stages in the Court. At this time, the Company is not able to predict the outcome of these matters or whether they will have a material impact on the Company's business, financial condition, results of operations or cash flows.

On March 20, 2019, EJ LeJeune, a former employee of ESPADA Logistics and Security Group, LLC and ESPADA Caribbean LLC (together, "ESPADA") filed a putative collective and class action complaint in LeJeune v. Mammoth Energy Services, Inc. d/b/a Cobra Energy & ESPADA Logistics and Security Group, LLC, Case No. 5:19-cv-00286-JKP-ESC, in the U.S. District Court for the Western District of Texas. On August 5, 2019, the Court granted the plaintiff's motion for leave to amend his complaint, dismissing Mammoth Energy Services, Inc. as a defendant, adding Cobra Acquisitions LLC ("Cobra") as a defendant, and adding ESPADA Caribbean LLC and two officers of ESPADA—James Jorrie and Jennifer Gay Jorrie—as defendants. The amended complaint alleges that the defendants jointly employed the plaintiff and all similarly situated workers and failed to pay them overtime as required by the Fair Labor Standards Act and Puerto Rico law. The complaint also alleges the following violations of Puerto Rico law: illegal deductions from workers' wages, failure to timely pay all wages owed, failure to pay a required severance when terminating workers without just cause, failure to pay for all hours worked, failure to provide required meal periods, and failure to pay a statutorily required bonus to eligible workers. Mr. LeJeune seeks to represent a class of workers allegedly employed by one or more defendants and paid a flat amount for each day worked regardless of how many hours were worked. The complaint seeks back wages, including overtime wages owed, liquidated damages equal to the overtime wages owed, attorneys' fees, costs, and pre- and post-judgment interest. On June 16, 2020, Cobra answered Mr. LeJeune's amended complaint, denying that it employed Mr. LeJeune and the putative class members and denying that they are entitled to relief from Cobra. All other defendants have also answered the amended complaint. The parties stipulated to conditional certification of a collective action, and on August 14, 2020, Court ordered that notice be sent to all individuals engaged by ESPADA to provide services to Cobra in Puerto Rico between January 21, 2017 and the present who were paid a day-rate. Notice was sent to putative class members on September 15, 2020, and the opt-in period closed on November 14, 2020. The parties informed the Court that that the plaintiff and the ESPADA defendants reached a settlement on November 5, 2021, and subsequently, that a settlement was reached between the plaintiffs and Cobra on December 6, 2021. The stipulation of dismissal as to all parties was filed with the Court and the case was dismissed on January 19, 2022.

On April 16, 2019, Christopher Williams, a former employee of Higher Power Electrical, LLC, filed a putative class and collective action complaint titled Christopher Williams, individually and on behalf of all others similarly situated v. Higher Power Electrical, LLC, Cobra Acquisitions LLC, and Cobra Energy LLC in the U.S. District Court for the District of Puerto Rico. On June 24, 2019, the complaint was amended to replace Mr. Williams with Matthew Zeisset as the named plaintiff. The plaintiff alleges that the Company failed to pay overtime wages to a class of workers in compliance with the Fair Labor Standards Act and Puerto Rico law. On August 21, 2019, upon request of the parties, the Court stayed proceedings in the lawsuit pending completion of individual arbitration proceedings initiated by Mr. Zeisset and opt-in plaintiffs. The arbitrations remain pending. Other claimants have subsequently initiated additional individual arbitration proceedings asserting similar claims. All complainants and the respondents have paid the filing fees necessary to initiate the arbitrations. The parties are currently engaged in discovery. The Company believes these claims are without merit and will vigorously defend the arbitrations. However, at this time, the Company is not able to predict the outcomes of these proceedings or whether they will have a material impact on the Company's business, financial condition, results of operations or cash flows.

In June 2019 and August 2019, the Company was served with three class action lawsuits filed in the Western District of Oklahoma. On September 13, 2019, the Court consolidated the three lawsuits under the case caption *In re Mammoth Energy Services, Inc. Securities Litigation*. On November 12, 2019, the plaintiffs filed their first amended complaint against Mammoth Energy Services, Inc., Arty Straehla, and Mark Layton. Pursuant to their first amended complaint, the plaintiffs brought a consolidated putative federal securities class action on behalf of all investors who purchased or otherwise acquired Mammoth Energy Services, Inc. common stock between October 19, 2017, and June 5, 2019, inclusive. On January 10, 2020, the defendants filed their motion to dismiss the first amended complaint. On March 9, 2020, the plaintiffs filed a second amended complaint for violation of federal securities laws which contains allegations substantially similar to those contained in the plaintiff's first amended complaint. On March 30, 2020, the defendants filed their motion to dismiss the second amended complaint. On January 26, 2021, the Court granted the motion to dismiss in part and denied the motion to dismiss in part. In April 2021 a settlement was reached and motion for preliminary approval was filed, which the Court granted on May 4, 2021. On September 21, 2021, the Court issued a final judgment approving the settlement, which released the defendants from all claims asserted in the litigation, or that could have been asserted arising from the subject matter of the litigation and the purchase or acquisition of Mammoth common stock during the class period in return for a cash payment in the amount of $11.0 million for the benefit of the settlement class. The settlement amount is covered in full under Mammoth's directors' and officers' insurance policy.

In September 2019, four derivative lawsuits were filed, two in the Western District of Oklahoma and two in the District of Delaware, purportedly on behalf of the Company and against its officers and directors. In October 2019, the plaintiffs in the two Oklahoma actions voluntarily dismissed their respective cases, with one plaintiff refiling his action in the District of Delaware. On September 13, 2019, the Court consolidated the three actions under the case caption In re Mammoth Energy Services, Inc. Consolidated Shareholder Litigation. On January 17, 2020, the plaintiffs filed their consolidated amended shareholder derivative complaint on behalf of Nominal Defendant, Mammoth Energy Services, Inc., and against Arty Straehla, Mark Layton, Arthur Amron, Paul V. Heerwagen IV, Marc McCarthy, Jim Palm, Matthew Ross, Arthur Smith, Gulfport Energy Corporation, and Wexford Capital LP. On October 5, 2021, the plaintiffs and Nominal Defendant Mammoth entered into the Stipulation and Agreement of Settlement (the "Stipulation") in the derivative action, which was preliminarily approved by the Court on October 28, 2021. The terms of the Stipulation required that, in exchange for the full release, discharge and dismissal with prejudice of the claims asserted against the defendants in the derivative action, (1) the individual defendants will cause the insurers under Mammoth's Directors' and Officers' ("D&O") insurance policy (the "D&O insurers") to pay $1.5 million to Mammoth, which Mammoth will use for general corporate purposes; and (2) Mammoth will adopt certain corporate governance reforms, which will further enhance Mammoth's current corporate governance policies. Additionally, the Stipulation provides that the individual defendants will cause the D&O insurers to pay, subject to Court approval, a separate payment of $0.5 million to plaintiffs' counsel for their attorneys' fees and expenses. The approval hearing was held on January 25, 2022 and the final order was entered. The settlement was covered in full under Mammoth's D&O insurance policy.

On September 10, 2019, the U.S. District Court for the District of Puerto Rico unsealed an indictment that charged the former president of Cobra Acquisitions LLC with conspiracy, wire fraud, false statements and disaster fraud. Two other individuals were also charged in the indictment. The indictment is focused on the interactions between a former FEMA official and the former president of Cobra. Neither the Company nor any of its subsidiaries were charged in the indictment. The Company is continuing to cooperate with the related investigation. Given the uncertainty inherent in the criminal litigation, it is not possible at this time to determine the potential outcome or other potential impacts that the criminal litigation could have on the Company. PREPA has stated in Court filings that it may contend the alleged criminal activity affects Cobra's entitlement to payment under its contracts with PREPA. Subsequent to the indictment, the Company received (i) a preservation request letter from the United States Securities and Exchange Commission ("SEC") related to documents relevant to an ongoing investigation it is conducting and (ii) a civil investigative demand ("CID") from the United States Department of Justice ("DOJ"), which requests certain documents and answers to specific interrogatories relevant to an ongoing investigation it is conducting. Both the aforementioned SEC and DOJ investigations are in connection with the issues raised in the criminal matter. Following the resignation of Jonathan Yellen from the Company's board of directors and the matters raised in the Company's Form 8-K filed on May 14, 2020, the Company received an expanded preservation request from the SEC. The Company is cooperating with both the SEC and DOJ and is not able to predict the outcome of these investigations or if either will have a material impact on the Company's business, financial condition, results of operations or cash flows.

On September 12, 2019, AL Global Services, LLC ("Alpha Lobo") filed a second amended third-party petition against the Company in an action styled Jim Jorrie v. Craig Charles, Julian Calderas, Jr., and AL Global Services, LLC v. Jim Jorrie v. Cobra Acquisitions LLC v. ESPADA Logistics & Security Group, LLC, ESPADA Caribbean LLC, Arty Straehla, Ken Kinsey, Jennifer Jorrie, and Mammoth Energy Services, Inc., in the 57th Judicial District in Bexar County, Texas. The petition alleges that the Company should be held vicariously liable under alter ego, agency and respondeat superior theories for Alpha Lobo's alleged claims against Cobra and Arty Straehla for aiding and abetting, knowing participation in and conspiracy to breach fiduciary duty in connection with Cobra's execution of an agreement with ESPADA Caribbean, LLC for security services related to Cobra's work in Puerto Rico. The case is currently subject to a statutory stay pending a ruling on the appeal of anti-SLAPP motions to dismiss filed by certain defendants. The Company believes these claims are without merit and will vigorously defend the action. However, at this time, the Company is not able to predict the outcome of this lawsuit or whether it will have a material impact on the Company's business, financial condition, results of operations or cash flows. Additionally, there is a parallel arbitration proceeding that has been initiated in which certain Defendants are seeking a declaratory judgment regarding Cobra's rights to terminate the Alpha Lobo contract and enter into a new contract with a third-party. On June 24, 2021, the arbitration panel ruled in favor of Cobra.

Subsequently, the trial Court in this action granted Cobra, the Company and Straehla's motion to compel arbitration. Alpha Lobo has not brought their claims in arbitration at this time.

The Company is involved in various other legal proceedings in the ordinary course of business. Although the Company cannot predict the outcome of these proceedings, legal matters are subject to inherent uncertainties and there exists the possibility that the ultimate resolution of these matters could have a material impact on the Company's business, financial condition, results of operations or cash flows.

Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at their date of hire. The plan allows eligible employees to contribute up to 92% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes discretionary matching contributions of up to 3% of an employee's compensation and may make additional discretionary contributions for eligible employees. For the years ended December 31, 2021, 2020 and 2019, the Company paid $1.8 million, $2.0 million and $3.3 million, respectively, in contributions to the plan.

20. Reporting Segments and Geographic Areas

Reporting Segments

As of December 31, 2021, the Company's revenues, income before income taxes and identifiable assets are primarily attributable to four reportable segments. The Company principally provides electric infrastructure services to private utilities, public investor-owned utilities and co-operative utilities and services in connection with on-shore drilling of oil and natural gas wells for small to large domestic independent oil and natural gas producers.

The Company's Chief Executive Officer and Chief Financial Officer comprise the Company's Chief Operating Decision Maker function ("CODM"). Segment information is prepared on the same basis that the CODM manages the segments, evaluates the segment financial statements and makes key operating and resource utilization decisions. Segment evaluation is determined on a quantitative basis based on a function of operating loss less impairment expense, as well as a qualitative basis, such as nature of the product and service offerings and types of customers.

As of December 31, 2021, the Company's four reportable segments include infrastructure services ("Infrastructure"), well completion services ("Well Completion"), natural sand proppant services ("Sand") and drilling services ("Drilling"). Prior to the year ended December 31, 2021, the Company included Aquawolf in its "All Other" reconciling column. Based on its assessment of FASB ASC 280, *Segment Reporting*, guidance at December 31, 2021, the Company changed its presentation in 2021 to move Aquawolf to the Infrastructure segment. The results for the years ended December 31, 2020 and 2019 have been retroactively adjusted to reflect this change.

The Infrastructure segment provides electric utility infrastructure services to government-funded utilities, private utilities, public investor-owned utilities and co-operative utilities in the northeastern, southwestern, midwestern and western portions of the United States. The Well Completion segment provides hydraulic fracturing and water transfer services primarily in the Utica Shale of Eastern Ohio, Marcellus Shale in Pennsylvania and the mid-continent region. The Sand segment mines, processes and sells sand for use in hydraulic fracturing. The Sand segment primarily services the Utica Shale, Permian Basin, SCOOP, STACK and Montney Shale in British Columbia and Alberta, Canada. During certain of the periods presented, the Drilling segment provided contract land and directional drilling services primarily in the Permian Basin and mid-continent region.

During certain of the periods presented, the Company also provided aviation services, coil tubing services, equipment rental services, full service transportation, crude oil hauling services, remote accommodation and equipment manufacturing. The businesses that provide these services are distinct operating segments, which the CODM reviews independently when making key operating and resource utilization decisions. None of these operating segments meet the quantitative thresholds of a reporting segment and do not meet the aggregation criteria set forth in ASC 280 *Segment Reporting.* Therefore, results for these operating segments are included in the column titled "All Other" in the tables below. Additionally, assets for corporate activities, which primarily include cash and cash equivalents, inter-segment accounts receivable, prepaid insurance and certain property and equipment, are included in the All Other column. Although Mammoth Energy Partners LLC, which holds these corporate assets, meets one of the quantitative thresholds of a reporting segment, it does not engage in business activities from which it may earn revenues and its results are not regularly reviewed by the Company's CODM when making key operating and resource utilization decisions. Therefore, the Company does not include it as a reportable segment.

Sales from one segment to another are generally priced at estimated equivalent commercial selling prices. Total revenue and total cost of revenue amounts included in the Eliminations column in the following tables include inter-segment transactions conducted between segments. Receivables due for sales from one segment to another and for corporate allocations to each segment are included in the Eliminations column for total assets in the following tables. All transactions conducted between segments are eliminated in consolidation. Transactions conducted by companies within the same reporting segment are eliminated within each reporting segment. The following tables set forth certain financial information with respect to the Company's reportable segments (in thousands):

Year Ended December 31, 2021	Infrastructure	Well Completion	Sand	Drilling	All Other	Eliminations	Total
Revenue from external customers	$ 93,403	$ 84,190	$ 30,880	$ 4,197	$ 16,292	$ —	$ 228,962
Intersegment revenues	—	144	3,980	124	2,218	(6,466)	—
Total revenue	93,403	84,334	34,860	4,321	18,510	(6,466)	228,962
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	90,363	58,782	27,232	6,102	15,847	—	198,326
Intersegment cost of revenues	196	5,770	—	—	500	(6,466)	—
Total cost of revenue	90,559	64,552	27,232	6,102	16,347	(6,466)	198,326
Selling, general and administrative	18,267	49,275	5,351	1,414	3,939	—	78,246
Depreciation, depletion, amortization and accretion	21,880	26,377	9,005	7,996	13,217	—	78,475
Impairment of goodwill	891	—	—	—	—	—	891
Impairment of other long-lived assets	665	—	—	—	547	—	1,212
Operating loss	(38,859)	(55,870)	(6,728)	(11,191)	(15,540)	—	(128,188)
Interest expense	3,925	1,107	474	293	607	—	6,406
Other (income) expense, net	(6,785)	1,073	(874)	(177)	(3,538)	—	(10,301)
Loss before income taxes	$ (35,999)	$ (58,050)	$ (6,328)	$ (11,307)	$ (12,609)	$ —	$ (124,293)
Total expenditures for property, plant and equipment	$ 627	$ 4,327	$ 484	$ 44	$ 361	$ —	$ 5,843
As of December 31, 2021:							
Intangible assets, net	$ 165	$ 1,995	$ —	$ —	$ 401	$ —	$ 2,561
Total assets	$ 427,626	$ 56,036	$ 156,519	$ 27,457	$ 129,202	$ (75,948)	$ 720,892

Year Ended December 31, 2020	Infrastructure	Well Completion	Sand	Drilling	All Other	Eliminations	Total
Revenue from external customers	$ 157,751	$ 87,201	$ 34,265	$ 7,746	$ 26,113	$ —	$ 313,076
Intersegment revenue	—	1,124	95	39	2,716	(3,974)	—
Total revenue	157,751	88,325	34,360	7,785	28,829	(3,974)	313,076
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	124,232	45,647	25,955	10,757	25,430	—	232,021
Intersegment cost of revenues	323	1,836	—	152	1,663	(3,974)	—
Total cost of revenue	124,555	47,483	25,955	10,909	27,093	(3,974)	232,021
Selling, general and administrative	27,261	23,039	7,807	3,149	5,929	—	67,185
Depreciation, depletion, amortization and accretion	29,373	30,411	9,771	10,039	15,723	—	95,317
Impairment of goodwill	—	53,406	—	—	1,567	—	54,973
Impairment of other long-lived assets	—	4,203	—	326	8,368	—	12,897
Operating loss	(23,438)	(70,217)	(9,173)	(16,638)	(29,851)	—	(149,317)
Interest expense	2,794	1,130	312	454	707	—	5,397
Other (income) expense, net	(32,437)	(2,274)	1,839	(227)	(1,839)	—	(34,938)
Income (loss) before income taxes	$ 6,205	$ (69,073)	$ (11,324)	$ (16,865)	$ (28,719)	$ —	$ (119,776)
Total expenditures for property, plant and equipment	$ 258	$ 4,358	$ 1,073	$ 432	$ 716	$ —	$ 6,837
As of December 31, 2020:							
Intangible assets, net	$ 1,063	$ 2,683	$ —	$ —	$ 1,028	$ —	$ 4,774
Total assets	$ 437,296	$ 99,247	$ 172,927	$ 36,252	$ 136,422	$ (57,582)	$ 824,562

Year Ended December 31, 2019	Infrastructure	Well Completion	Sand	Drilling	All Other	Eliminations	Total
Revenue from external customers	$ 210,712	$ 241,951	$ 67,267	$ 31,728	$ 73,354	$ —	$ 625,012
Intersegment revenues	2,573	1,851	29,796	236	15,232	(49,688)	—
Total revenue	213,285	243,802	97,063	31,964	88,586	(49,688)	625,012
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	160,731	174,816	87,637	35,925	84,679	—	543,788
Intersegment cost of revenues	12,820	31,727	15	1,028	4,158	(49,748)	—
Total cost of revenue	173,551	206,543	87,652	36,953	88,837	(49,748)	543,788
Selling, general and administrative	23,616	10,889	5,006	4,177	7,864	—	51,552
Depreciation, depletion, amortization and accretion	30,349	40,159	14,050	13,143	19,332	—	117,033
Impairment of goodwill	—	23,423	2,684	—	7,557	—	33,664
Impairment of other long-lived assets	—	—	—	2,955	4,403	—	7,358
Operating loss	(14,231)	(37,212)	(12,329)	(25,264)	(39,407)	60	(128,383)
Interest expense	1,674	1,228	193	862	1,001	—	4,958
Other expense	(41,949)	580	67	(9)	(905)	—	(42,216)
(Loss) income before income taxes	$ 26,044	$ (39,020)	$ (12,589)	$ (26,117)	$ (39,503)	$ 60	$ (91,125)
Total expenditures for property, plant and equipment	$ 3,456	$ 14,703	$ 2,877	$ 3,156	$ 11,569	$ —	35,761
As of December 31, 2019:							
Intangible assets, net	$ 1,296	$ 3,371	$ —	$ —	$ 1,121	$ —	$ 5,788
Total assets	$ 420,755	$ 172,608	$ 189,415	$ 55,273	$ 166,406	$ (52,072)	$ 952,385

Geographic Areas

The following table presents consolidated revenues by country based on sales destination of the products or services (in thousands):

	Year Ended December 31,		
	2021	2020	2019
United States	$ 217,958	$ 302,205	$ 516,276
Puerto Rico	—	53	96,630
Canada	10,685	10,723	11,946
Other	319	95	160
Total	$ 228,962	$ 313,076	$ 625,012

The following table presents long-lived assets, excluding deferred income tax assets, by country (in thousands):

	Year Ended December 31,		
	2021	2020	2019
United States	$ 258,666	$ 342,838	$ 526,584
Canada	13,349	16,976	18,821
Total	$ 272,015	$ 359,814	$ 545,405

21. Subsequent Events

As discussed above, on February 28, 2022, the Company entered into a fourth amendment to its revolving credit facility. See Note 10 above for details.

Subsequent to December 31, 2021, the Company ordered additional capital equipment with aggregate commitments of $2.7 million.

Subsequent to December 31, 2021, the Company entered into two three-year real estate operating lease agreements with aggregate commitments of $0.6 million.

February 28, 2022

PNC BANK, NATIONAL ASSOCIATION,
as Agent for and on behalf of the
Lenders as referred to below
2100 Ross Avenue, Suite 1850
Dallas, Texas 75201
Attention: Relationship Manager -Mammoth Energy

Re: Fourth Amendment to Amended and Restated Revolving Credit and Security Agreement

Ladies and Gentlemen:

PNC BANK, NATIONAL ASSOCIATION ("PNC"), as agent for the Lenders from time to time party to the Credit Agreement referred to below (PNC, in such capacity, together with its successors and assigns in such capacity, the "Agent") for the Lenders from time to time party to the Credit Agreement referred to below, the Lenders party thereto, MAMMOTH ENERGY SERVICES, INC., a corporation organized under the laws of the State of Delaware (formerly Mammoth Energy Services Inc.) ("Mammoth"), as a Borrower, and together with the other Borrowers party to the Credit Agreement referred to below, have previously entered into financing arrangements pursuant to that certain Amended and Restated Revolving Credit and Security Agreement, dated as of October 19, 2018, by and among Borrowers, Agent, and Lenders (as previously amended by the First Amendment to Amended and Restated Revolving Credit and Security Agreement, dated November 5, 2019, the Second Amendment to Amended and Restated Revolving Credit and Security Agreement, dated as of February 26, 2020, the Third Amendment to Amended and Restated Revolving Credit and Security Agreement, dated as of November 3, 2021, as amended hereby and as the same may hereafter be further amended, modified, supplemented, extended, renewed, restated or replaced, the "Credit Agreement"), and the Other Documents referred to therein or at any time executed and/or delivered in connection therewith or related thereto. All capitalized terms used herein shall have the meaning assigned thereto in the Credit Agreement, unless otherwise defined herein.

Borrowers have requested that Agent and Lenders (a) amend certain financial covenants in the Credit Agreement and eliminate the Leverage Ratio financial covenant, and (b) provide for certain other amendments to the Credit Agreement; and Agent and Lenders are willing to agree to the foregoing, on and subject to the terms and conditions set forth in this letter agreement Re: Fourth Amendment to Amended and Restated Revolving Credit and Security Agreement (this "Fourth Amendment").

In consideration of the foregoing, the mutual agreements and covenants contained herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

1. Acknowledgment of Obligations, Security Interests and Financing Agreements.

(a) Acknowledgment of Obligations. Borrowers hereby acknowledge, confirm and agree that, as of the date hereof, Borrowers are unconditionally indebted to Agent and Lenders as of the close of business on February 25, 2022, in respect of the Advances in the aggregate principal amount of $83,536,804.68 and outstanding Letters of Credit in the Undrawn Amount of $8,538,184.50, together with interest accrued and accruing on the Advances, and all fees, costs, expenses and other sums and charges payable by Borrowers to Agent and Lenders pursuant to the Credit Agreement and the Other Documents, all of which are unconditionally owing by Borrowers to Agent and Lenders pursuant to the Credit Agreement and the Other Documents, in each case without offset, defense or counterclaim of any kind, nature or description whatsoever.

(b) Acknowledgment of Security Interests. Borrowers hereby acknowledge, confirm and agree that Agent and Lenders have, and shall continue to have, valid, enforceable and perfected security interests in and Liens upon the Collateral heretofore granted by Borrowers to Agent, for the benefit of Lenders and the other Secured Parties, pursuant to the Credit Agreement and the Other Documents or otherwise granted to or held by Agent.

(c) Binding Effect of Credit Agreement and Other Documents. Borrowers hereby acknowledge, confirm and agree that: (i) each of the Credit Agreement and the Other Documents to which Borrowers are a party has been duly executed and delivered to Agent and Lenders by Borrowers, and each is in full force and effect as of the date hereof, (ii) the agreements and obligations of Borrowers contained in the Credit Agreement and such Other Documents to which they are a party and in this Fourth Amendment constitute the legal, valid and binding Obligations of Borrowers, enforceable against them in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws relating to or limiting creditors' rights generally or by equitable principles relating to enforceability, and Borrowers have no valid defense to the enforcement of such Obligations, and (iii) Agent and Lenders are and shall be entitled to the rights, remedies and benefits provided for in the Credit Agreement and the Other Documents and pursuant to applicable law, but subject to the terms and conditions of this Fourth Amendment.

2. Amendments to Loan Agreement and Certain Additional Covenants.

(a) Additional Definitions. As used herein, the following terms shall have the meanings given to them below and the Credit Agreement and the Other Documents are hereby amended to include, in addition and not in limitation, the following definitions:

"Affected Financial Institution" shall mean (a) any EEA Financial Institution or (b) any UK Financial Institution.

"Bail-In Legislation Schedule" shall mean the EU Bail-In Legislation Schedule published by the Loan Market Association (or any successor person), as in effect from time to time.

"Disposition" shall have the meaning set forth in the definition of Eligible Equipment Sublimit.

"Disposed Equipment" shall have the meaning set forth in the definition of Eligible Equipment Sublimit.

"Disposed Equipment Proceeds Carveout" shall have the meaning set forth in the definition of Eligible Equipment Sublimit.

"Fourth Amendment" shall mean the letter agreement Re: Fourth Amendment to Amended and Restated Revolving Credit and Security Agreement, dated as of Fourth Amendment Effective Date, by and among Agent, Lenders, and Borrowers.

"Fourth Amendment Effective Date" shall mean the date of the Fourth Amendment.

"Fourth Amendment Fee Letter" shall mean the Fee Letter, dated as of February 28, 2022, executed among Borrowers, PNC Capital Markets LLC and PNC.

"MasTec" shall mean, collectively, MasTec Renewables Puerto Rico, LLC and MasTec, Inc.

"MasTec Settlement Agreement" shall mean the Settlement Agreement, dated August 2, 2021, executed among Cobra Acquisitions, LLC, Mammoth and MasTec.

"MasTec Settlement Payment" shall mean the two installment payments to be paid by Cobra Acquisitions, LLC to MasTec pursuant to the MasTec Settlement Agreement in the amount of $9,250,000 each on August 1, 2022 and December 1, 2022, respectively, together with interest that is payable with respect to each such installment payment at the rate set forth in the MasTec Settlement Agreement.

"PREPA" shall mean Puerto Rico Electric Power Authority.

"PREPA Claim" shall mean the claims of Cobra Acquisitions LLC asserted in PREPA's adjustment of debts proceeding filed pursuant to Title III of the Puerto Rico Oversight, Management, and Economic Stability Act in the United States District Court for the District of Puerto Rico.

"PREPA Claim Proceeds" shall mean any and all cash payments that are at any time received by the Loan Parties on account of the PREPA Claim.

"Resolution Authority" shall mean an EEA Resolution Authority or, with respect to any UK Financial Institution, a UK Resolution Authority.

"UK Financial Institution" shall mean any BRRD Undertaking (as such term is defined under the PRA Rulebook (as amended from time to time) promulgated by the United Kingdom Prudential Regulation Authority) or any person falling within IFPRU 11.6 of the FCA Handbook (as amended from time to time) promulgated by the United Kingdom Financial Conduct Authority, which includes certain credit institutions and investment firms, and certain affiliates of such credit institutions or investment firms.

"UK Resolution Authority" shall mean the Bank of England or any other public administrative authority having responsibility for the resolution of any UK Financial Institution.

(b) Applicable Margin. The definition of "Applicable Margin" set forth in Section 1.2 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

““Applicable Margin” shall mean (a) four percent (4.00%) for all Revolving Advances and Swing Loans at all times solely during the period from and after the Fourth Amendment Effective Date through and including the last day of the first fiscal quarter following the Fourth Amendment Effective Date for which Borrowers have a Fixed Charge Coverage Ratio of at least 1.10:1.00 for the four (4) fiscal quarter period then ending (the “Applicable Margin Reduction Event”, and (b) three and one-half percent (3.50%) for all Revolving Advances and Swing Loans from and after the occurrence of the Applicable Margin Reduction Event.

(c) The definition of “Bail-In Legislation” set forth in Section 1.2 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

“Bail-In Legislation” shall mean (a) with respect to any EEA Member Country implementing Article 55 of Directive 2014/59/EU of the European Parliament and of the Council of the European Union, the implementing law, regulation rule or requirement for such EEA Member Country from time to time which is described in the EU Bail-In Legislation Schedule and (b) with respect to the United Kingdom, Part I of the United Kingdom Banking Act 2009 (as amended from time to time) and any other law, regulation or rule applicable in the United Kingdom relating to the resolution of unsound or failing banks, investment firms or other financial institutions or their affiliates (other than through liquidation, administration or other insolvency proceedings).

(d) Unavailability of LIBOR Rate Loans. Notwithstanding anything to the contrary set forth in Section 2.2 of the Credit Agreement or in any other Section, definition or provision of the Credit Agreement or any Other Document, at all times from and after the Fourth Amendment Effective Date, (i) Borrowers shall have no right to request or receive LIBOR Rate Loans for any Advance or to convert any existing Domestic Rate Loans to LIBOR Rate Loans, (ii) Agent and Lenders shall have no obligation whatsoever to provide LIBOR Rate Loans for any Advance or to convert any existing Domestic Rate Loans to LIBOR Rate Loans, (iii) all LIBOR Rate Loans that are outstanding on the Fourth Amendment Effective Date shall automatically convert to and shall constitute Domestic Rate Loans as of the expiration of each currently existing Interest Period with respect to each of such outstanding LIBOR Rate Loans, and (iv) all Advances made (or deemed made) by Agent and Lenders to Borrowers at any time from and after the Fourth Amendment Effective Date shall constitute Domestic Rate Loans.

(e) Commitment Amount. The definition of “Commitment Amount” in Section 1.2 of the Credit Agreement is hereby amended by amending and restating clause (ii) thereof in its entirety as follows:

“(ii) as to any Lender that is a New Lender, the Commitment Amount provided for in the joinder signed by such New Lender under Section 2.24(a)(ix) in each case as the same may be adjusted upon any increase by such Lender pursuant to Section 2.24 hereof, upon any decrease thereof pursuant to Section 2.25 hereof, or any assignment by or to such Lender pursuant to Section 16.3(c) or (d) hereof.”

(f) Fixed Charge Coverage Ratio. The definition of "Fixed Charge Coverage Ratio" in Section 1.2 of the Credit Agreement is hereby amended by (i) deleting the phrase "for the four fiscal quarter period then ending" set forth on the second line of such definition and replacing it with "for any applicable period", and (ii) adding the following sentence at the end of such definition:

> "Notwithstanding the foregoing, for purposes of the calculation of the Fixed Charge Coverage Ratio, EBITDA and Adjusted EBITDA shall expressly exclude all accrued interest with respect to the PREPA Claim that would otherwise be included by Borrowers in the calculation of EBITDA and Adjusted EBITDA for any period."

(g) The definition of "Write-Down and Conversion Powers" set forth in Section 1.2 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

> "Write-Down and Conversion Powers" shall mean, (a) with respect to any EEA Resolution Authority, the write-down and conversion powers of such EEA Resolution Authority from time to time under the Bail-In Legislation for the applicable EEA Member Country, which write-down and conversion powers are described in the EU Bail-In Legislation Schedule, and (b) with respect to the United Kingdom, any powers of the applicable Resolution Authority under the Bail-In Legislation to cancel, reduce, modify or change the form of a liability of any UK Financial Institution or any contract or instrument under which that liability arises, to convert all or part of that liability into shares, securities or obligations of that person or any other person, to provide that any such contract or instrument is to have effect as if a right had been exercised under it or to suspend any obligation in respect of that liability or any of the powers under that Bail-In Legislation that are related to or ancillary to any of those powers.

(h) Mandatory Prepayment with PREPA Claim Proceeds. Section 2.20(b) of the Credit Agreement is hereby amended by amending and restating the first sentence thereof in its entirety to read as follows:

> "(b) Notwithstanding anything to the contrary set forth in Section 2.8 or Section 2.20(a) above, at all times from and after the Fourth Amendment Effective Date, Borrowers shall promptly (but in no event more than three (3) Business Days following receipt of any PREPA Claim Proceeds) remit to Agent (or cause to be remitted to Agent) all PREPA Claim Proceeds that are at any time received by Credit Parties and, until the date of delivery thereof to Agent, such PREPA Claim Proceeds shall be and shall be deemed to be held in trust exclusively for Agent."

(i) Reduction in Maximum Revolving Advance Amount. Section 2.25 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

> ""2.25. Reduction of Maximum Revolving Advance Amount. Borrowing Agent may no more than once during each period of twelve months, on at least three (3) Business Days' prior

written notice received by Agent (which shall promptly advise each Lender thereof) permanently reduce the Maximum Revolving Advance Amount, minimum increments of $10,000,000 to an amount not less than the amount of the then outstanding Advances. The Maximum Revolving Advance Amount shall be automatically (without any notice to Borrowers) permanently reduced by an amount equal to fifty percent (50%) of all PREPA Claim Proceeds that have been remitted to Agent pursuant to Section 2.20(b), provided, however, that such reduction shall not reduce the Maximum Revolving Advance Amount below the sum of (i) Eligible Receivables and (ii) Eligible Unbilled Receivables, in each case as set forth in the Borrowing Base Certificate most recently delivered to Agent at the time of such reduction. All reductions of the Maximum Revolving Advance Amount shall be applied ratably among the Lenders according to their respective Commitment Amounts. For the avoidance of doubt, voluntary prepayments on the unutilized portion of the Maximum Revolving Advance Amount coupled with any permanent reduction of the Maximum Revolving Advance Amount effected pursuant to the immediately preceding sentence will be subject to (x) payment of breakage costs in the case of a prepayment of LIBOR Rate Loans other than on the last day of the relevant Interest Period, and (y) any other provisions contained in this Agreement."

(j) Amendment of Eligible Equipment Sublimit. The definition of "Eligible Equipment Sublimit" is hereby amended by amending and restating in its entirety the *proviso* in clause (b) of such definition as follows:

"provided, however, (i) in the event that Borrower sells, transfers or otherwise disposes of any Eligible Equipment included in the calculation of clause (vi) of Section 2.1(a)(y) or any such Eligible Equipment is subject to a casualty event after the Second Amendment Effective Date (any such sale, transfer, disposition or casualty event being referred to as a "Disposition", and any Eligible Equipment that is the subject of a Disposition being referred to as "Disposed Equipment"), the Eligible Equipment Sublimit shall be thereupon further reduced by an amount equal to the Equipment Advance Rate times the net orderly liquidation value of such Disposed Equipment pursuant to the most recent NOLV Appraisal, except that Dispositions of Disposed Equipment pursuant to one or more Permitted Sale-Leaseback Transactions that occur subsequent to the Fourth Amendment Effective Date shall, in an aggregate amount of up to $5,000,000 in proceeds arising therefrom, not result in any reduction in the Eligible Equipment Sublimit (the "Disposed Equipment Proceeds Carveout"), (ii) in the event that PREPA Claim Proceeds are at any time remitted to Agent pursuant to Section 2.20(b), then the Eligible Equipment Sublimit shall be reduced by an amount equal to fifty percent (50%) of all PREPA Claim Proceeds that have been remitted to Agent (regardless of whether such PREPA Claim Proceeds are applied to repay Advances or are made available to Borrowing Agent in accordance with Section 2.20(b)), and (iii) a reduction in the Eligible Equipment Sublimit as a result of a Disposition in any calendar quarter pursuant to the immediately preceding clause (i) or clause (ii) shall in no event limit or affect the regularly scheduled Quarterly Reduction for any calendar quarter thereafter pursuant to this clause (b).

(k) Elimination of Accordion. Section 2.24 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"2.24 [Reserved]"

(l) Rolling Stock Lien Perfection. Section 4.13 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"4.13. Rolling Stock and other Titled Vehicles. Notwithstanding anything to the contrary set forth in Section 4.2 or any other Section of this Agreement which obligates Borrowers to take action that may be necessary to maintain the perfection of Agent's Liens with respect to all Collateral, solely in the case of rolling stock and other Equipment that is subject to a certificate of title and with respect to which Agent's Liens therein can only be perfected by notation of Agent's Liens on the certificate of title issued with respect thereto ("Certificated Collateral"), Borrowers shall deliver to Agent each certificate of title for Certificated Collateral with an individual value in excess of $74,999.99 (the "Minimum Certificated Collateral Value"; which valuation of Certificated Collateral shall be determined at any time based upon the then most recent appraisal received by Agent pursuant to Section 4.7) for notation by Agent of its Lien thereon, together with the following documents, each in form and substance reasonably satisfactory to Agent: (i) a fully-executed, notarized power of attorney authorizing Corporation Service Company (or any other third party agency at any time retained by Agent to perfect Agent's Liens on Certificated Collateral) to perfect Agent's Liens, on behalf of Agent, on each certificate of title for Certificated Collateral; (ii) new unencumbered titles for each such item of Certificated Collateral within ten (10) Business Days of receipt by a Loan Party of a new title certificate for such Certificated Collateral, and such Loan Party shall use its commercially reasonably best efforts to obtain and deliver to Agent each such new title certificate within thirty (30) days of purchase; and (iii) solely in the case of titles for each item of Certificated Collateral with a valuation in excess of the Minimum Certificated Collateral Value as of the Fourth Amendment Effective Date, each applicable Loan Party that is the registered title owner of such Certificated Collateral shall use its commercially reasonably best efforts to deliver to Agent, within thirty (30) days after the Fourth Amendment Effective Date (or such later date as shall be approved by Agent in its discretion), each such title certificate issued with respect to such Certificated Collateral. Additionally, each Loan Party acknowledges and agrees that after the occurrence and during the continuance of an Event of Default, upon Agent's request, Loan Parties shall to deliver to Agent the items described in clauses (i) and (ii) above with respect to all items of Certificated Collateral as shall be required by Agent (including (without limitation) all such

Certificated Collateral with an individual value of less than Minimum Certificated Collateral Value)."

(m) Minimum Adjusted EBITDA Financial Covenant. Section 6.5(a) of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"(a) Minimum Adjusted EBITDA. Maintain Adjusted EBITDA for the five (5) months ending May 31, 2022 of not less than $4,700,000; provided, that, the calculation of EBITDA and Adjusted EBITDA for purposes of this financial covenant shall expressly exclude all accrued interest with respect to the PREPA Claim that would otherwise be included by Borrowers in the calculation of EBITDA and Adjusted EBITDA for any period."

(n) Elimination of Leverage Ratio. Section 6.5(b) of the Credit Agreement is hereby is hereby amended and restated in its entirety to read as follows:

"6.5(b) [Reserved]"

(o) Minimum Excess Availability. Section 6.5(c) of the Credit Agreement is hereby is hereby amended and restated in its entirety to read as follows:

" (c) Minimum Excess Availability. Maintain Excess Availability in an amount not less than (a) $7,500,000 at all times during the period from and after the Fourth Amendment Effective Date through and including the earlier to occur of (i) March 31, 2022 and (ii) the date on which Agent shall have received proceeds of Permitted Sale-Leaseback Transactions that occur subsequent to the Fourth Amendment Effective Date in an aggregate amount equal to the Disposed Equipment Proceeds Carveout, and (b) $10,000,000 at all times thereafter; provided, however, that, (i) notwithstanding anything to the contrary contained in Section 10.5 of the Credit Agreement, if Borrowers fail to comply with this covenant on any day, an Event of Default shall not be deemed to have occurred as a result thereof unless Excess Availability remains below the amount required by this Section 6.5(c) for a total of three (3) consecutive Business Days, inclusive of the first day on which such non-compliance occurred, and (ii) during such three (3) Business Day period, consistent with Section 8.2(b) hereof, no Advances shall be made and no Letters of Credit shall be issued to Borrowers, except that Agent, in its sole discretion, may continue to make Advances notwithstanding the existence of such Default or Event of Default arising from such non-compliance, and any Advances so made shall not be deemed a waiver of any such Default or Event of Default. The Minimum Excess Availability shall be reduced automatically upon any reduction in Maximum Revolving Advance amount under Section 2.25 in an amount based upon the same percentage by which the Maximum Revolving Advance has been so reduced."

(p) Fixed Charge Coverage Ratio. Section 6.5(d) of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"(d) Fixed Charge Coverage Ratio. Maintain a Fixed Charge Coverage Ratio of at least (i) 0.85:1.00 for the six (6) months ending as of June 30, 2022, (ii) 1.10:1.00 for the nine (9) months ending as of September 30, 2022, and (iii) 1.10:1.00 for the four (4) fiscal quarter period ending as of the fiscal quarter ending December 31, 2022 and for each four (4) fiscal quarter period ending as of the last day of each fiscal quarter thereafter."

(q) Acquisitions, Investments, Dividends and Distributions Prohibited. Notwithstanding anything to the contrary set forth in Section 7.1(a), Section 7.4 and Section 7.7 of the Credit Agreement or any defined terms that are used in such Sections, from and after the Fourth Amendment Effective Date, no Credit Party shall (i) consummate any Permitted Acquisitions, (ii) enter into any Permitted Joint Venture Investments, (iii) consummate any transaction that would otherwise constitute a Permitted Investment pursuant to clause (f) of the definition of Permitted Investments with respect to Unrestricted Subsidiaries or clause (i) thereof, except that, from and after the Fourth Amendment Effective Date, Credit Parties shall be permitted to consummate any transaction that would constitute a Permitted Investment pursuant to clause (f) of the definition of Permitted Investment so long as (A) no Default or Event of Default then exists or will result therefrom and (B) after giving effect to such Permitted Investment in an Unrestricted Subsidiary, pro forma Excess Availability will be no less than 22.5% of the Maximum Available Credit, or (iv) declare, pay or make any dividend or distribution on any Equity Interests of any Borrower that would otherwise constitute Permitted Dividends (other than dividends or distributions payable in its Equity Interests, or split-ups or reclassifications of its Equity Interests).

(r) Restricted Payments. Section 7.17 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"7.17. Prepayment of Indebtedness; Certain Restricted Payments.

(a) If an Event of Default has occurred and continues, at any time, directly or indirectly, prepay any Indebtedness (other than (i) to Lenders, (ii) to another Credit Party or (iii) Purchase Money Indebtedness or Capitalized Lease Obligations), or repurchase, redeem, retire or otherwise acquire any Indebtedness of any Borrower, without the consent of Required Lenders.

(b) Pay or prepay any MasTec Settlement Payment unless on the date of any such payment or prepayment and after giving pro forma effect thereto, (i) no Default or Event of Default has occurred and is then continuing and (ii) Borrower shall have Excess Availability of not less than $20,000,000."

(s) Bail-In of Affected Financial Institutions. Section 16.22 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"16.18. Acknowledgment and Consent to Bail-In of Affected Financial Institutions. Notwithstanding anything to the contrary contained in this Agreement, any Other

Document, or any other agreement, arrangement or understanding among Agent, Lenders and the Loan Parties, Agent, each Lender and each Loan Party acknowledges that any liability of any Affected Financial Institution arising under this Agreement or any Other Document, to the extent such liability is unsecured, may be subject to the Write-Down and Conversion Powers of the applicable Resolution Authority and agrees and consents to, and acknowledges and agrees to be bound by:

(a) the application of any Write-Down and Conversion Powers by the applicable Resolution Authority to any such liabilities arising hereunder or under any Other Document which may be payable to it by any party hereto that is an Affected Financial Institution; and

(b) the effects of any Bail-In Action on any such liability, including, if applicable:

(i) a reduction in full or in part or cancellation of any such liability;

(ii) a conversion of all, or a portion of, such liability into shares or other instruments of ownership in such Affected Financial Institution, its parent undertaking, or a bridge institution that may be issued to it or otherwise conferred on it, and that such shares or other instruments of ownership will be accepted by it in lieu of any rights with respect to any such liability under this Agreement or any Other Document; or

(iii) the variation of the terms of such liability in connection with the exercise of the Write-Down and Conversion Powers of the applicable Resolution Authority."

3. Financial Covenant Compliance Waiver. Notwithstanding anything to the contrary set forth in Sections 6.5(b) and 6.5(d) of the Credit Agreement (the "Applicable Covenant Sections"), the Lenders hereby waive compliance by the Credit Parties with the Applicable Covenant Sections for the fiscal quarters ending September 30, 2021 and December 31, 2021, respectively.

4. Representations, Warranties and Covenants. Credit Parties hereby represent, warrant and covenant to Agent and Lenders the following (which shall survive the execution and delivery of this Fourth Amendment), the truth and accuracy of which are a continuing condition of the making of Advances to Borrowers:

(a) This Fourth Amendment and each other agreement or instrument to be executed and delivered by Credit Parties in connection herewith (collectively, together with this Fourth Amendment, the "Amendment Documents") have been duly authorized, executed and delivered by all necessary action on the part of Credit Parties, and the agreements and obligations of Credit Parties contained herein and therein constitute the legal, valid and binding obligations of Credit Parties, enforceable against them in accordance with their terms, except as enforceability is limited by bankruptcy, insolvency, reorganization, receivership, moratorium or other laws affecting creditor's rights generally and by general principles of equity;

(b) The execution, delivery and performance of this Fourth Amendment (i) are all within Credit Parties' corporate or limited liability company powers, as applicable, (ii) are not in contravention of law or the terms of Credit Parties' certificate or articles of organization or formation, operating agreement or other organizational documentation, or any indenture, agreement or undertaking to which Credit Parties are a party or by which Credit Parties or their property are bound and (iii) shall not result in the creation or imposition of any Lien, claim, charge or encumbrance upon any of the Collateral, other than Permitted Encumbrances;

(c) All of the representations and warranties set forth in the Credit Agreement and the Other Documents, each as amended hereby, are true and correct in all material respects on and as of the date hereof, as if made on the date hereof, except to the extent any such representation or warranty is made as of a specified date, in which case such representation or warranty shall have been true and correct in all material respects as of such date; and

(d) After giving effect to this Fourth Amendment, no Default or Event of Default exists as of the date of this Fourth Amendment.

5. Conditions Precedent. The amendments set forth in Section 2 of this Fourth Amendment and the other agreements set forth in this Fourth Amendment shall not be effective until each of the following conditions precedent are satisfied in a manner satisfactory to Agent:

(a) the receipt by Agent of this Fourth Amendment, duly authorized and executed by Credit Parties, Lenders and Agent, duly authorized and executed by Credit Parties and Agent;

(b) payment by Borrowers to Agent (for the benefit of Agent and Lenders in accordance with separate agreements between Agent and each Lender), of the fees set forth in Fourth Amendment Fee Letter; and

(c) immediately after giving effect to the amendments and agreements set forth herein, there shall exist no Default and no Event of Default.

6. Effect of this Amendment. This Fourth Amendment constitutes the entire agreement of the parties with respect to the subject matter hereof and thereof, and supersedes all prior oral or written communications, memoranda, proposals, negotiations, discussions, term sheets and commitments with respect to the subject matter hereof and thereof. This Fourth Amendment constitutes an Other Document. Except as expressly amended and waived pursuant hereto, no other changes or modifications or waivers to Credit Agreement and the Other Documents are intended or implied, and in all other respects the Credit Agreement and Other Documents are hereby specifically ratified, restated and confirmed by all parties hereto as of the effective date hereof. To the extent that any provision of the Credit Agreement or any of the Other Documents are inconsistent with the provisions of this Amendment, the provisions of this Amendment shall control.

7. Release of Agent and Lenders; Covenant Not to Sue.

(a) In consideration of the agreements of Agent and Lenders contained herein and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, Credit Parties, on behalf of themselves and their agents, representatives, officers, directors, advisors, employees, subsidiaries, affiliates, successors and assigns (collectively, "Releasor"), hereby absolutely, unconditionally and irrevocably release and forever discharge Agent or any or all of the Lenders in any capacity and their respective affiliates, subsidiaries, shareholders and "controlling persons" (within the meaning of the federal securities laws), and their respective successors and assigns and each and all of the officers, directors, employees, agents, attorneys and other representatives of each of the foregoing (Agent and Lenders and all such other parties being hereinafter referred to collectively as the "Lender Releasees" and individually as a "Lender Releasee"), of and from all demands, actions, causes of action, suits, covenants, contracts, controversies, agreements, promises, sums of money, accounts, bills, reckonings, damages and any and all other claims, counterclaims, defenses, rights of set-off, demands and liabilities whatsoever (individually, a "Claim" and collectively, "Claims") of every kind and nature, known or unknown, suspected or unsuspected, both at law and in equity, which such Releasor may now or hereafter own, hold, have or claim to have against the Lender Releasees or any of them for, upon, or by reason of any nature, cause or thing whatsoever which arises from the beginning of the world to the day of execution of this Fourth Amendment, in each case solely for or on account of, or in relation to, or in any way in connection with the Credit Agreement or any of the Other Documents, as amended and supplemented through the date hereof.

(b) Credit Parties understand, acknowledge and agree that the release set forth above may be pleaded as a full and complete defense and may be used as a basis for an injunction against any action, suit or other proceeding which may be instituted, prosecuted or attempted in breach of the provision of such release.

(c) Credit Parties agree that no fact, event, circumstance, evidence or transaction which could now be asserted or which may hereafter be discovered shall affect in any manner the final and unconditional nature of the release set forth above.

(d) Credit Parties, on behalf of themselves and their successors, assigns, and other legal representatives, hereby absolutely, unconditionally and irrevocably covenant and agree with each Releasee that they will not sue (at law, in equity, in any regulatory proceeding or otherwise) any Releasee on the basis of any Claim released, remised and discharged by Releasors pursuant to Section 6(a) above. If any Releasor violates the foregoing covenant, such Releasor agrees to pay, in addition to such other damages as any Releasee may sustain as a result of such violation, all reasonable and documented attorneys' fees and costs incurred by any Releasee as a result of such violation.

8. Reviewed by Attorneys. Credit Parties represent and warrant that they: (a) understand fully the terms of this Fourth Amendment and the consequences of the execution and delivery hereof, (b) have been afforded an opportunity to have this Fourth Amendment reviewed by, and to discuss the same with, such attorneys and other persons as Credit Parties may wish, and (c) have each entered into this Fourth Amendment of its own free will and accord and without threat, duress or other coercion of any kind by any person. Credit Parties acknowledge and agree that this Fourth Amendment shall not be construed more favorably in favor of Borrowers, on the one hand, or Agent and Secured Parties, on the other hand, based upon which party drafted the same, it being acknowledged that Agent and Secured Parties and Credit Parties contributed substantially to the negotiation and preparation of this Fourth Amendment.

9. Further Assurances. Credit Parties shall execute and deliver such additional documents and take such additional action as may be reasonably requested by Agent to effectuate the provisions and purposes of this Fourth Amendment.

10. Governing Law. The rights and obligations hereunder of each of the parties hereto shall, in accordance with Section 5-1401 of the General Obligations Law of the State of New York, be governed by and construed in accordance with the laws of the State of New York applied to contracts to be performed wholly within the State of New York.

11. Binding Effect. This Fourth Amendment shall be binding upon and inure to the benefit of each of the parties hereto and their respective successors and assigns.

12. Counterparts. This Fourth Amendment may be executed in any number of counterparts, but all of such counterparts shall together constitute but one and the same agreement. In making proof of this Fourth Amendment, it shall not be necessary to produce or account for more than one counterpart thereof signed by each of the parties hereto. Delivery of an executed counterpart of this Fourth Amendment by telecopier shall have the same force and effect as delivery of an original executed counterpart of this Fourth Amendment. Any party delivering an executed counterpart of this Fourth Amendment by telecopier also shall deliver an original executed counterpart of this Fourth Amendment, but the failure to deliver an original executed counterpart shall not affect the validity, enforceability, and binding effect of this Fourth Amendment as to such party or any other party.

[SIGNATURE PAGES FOLLOW]

MAMMOTH ENERGY SERVICES, INC.
MAMMOTH ENERGY PARTNERS LLC
REDBACK ENERGY SERVICES LLC
REDBACK COIL TUBING LLC
REDBACK PUMPDOWN SERVICES LLC
MUSKIE PROPPANT LLC
PANTHER DRILLING SYSTEMS LLC
BISON DRILLING AND FIELD SERVICES LLC
BISON TRUCKING LLC
ANACONDA RENTALS LLC
GREAT WHITE SAND TIGER LODGING LTD.
STINGRAY PRESSURE PUMPING LLC
SILVERBACK ENERGY LLC
MAMMOTH ENERGY INC.
BARRACUDA LOGISTICS LLC
WTL OIL, LLC
MR. INSPECTIONS LLC
SAND TIGER HOLDINGS INC.
MAMMOTH EQUIPMENT LEASING LLC
COBRA ACQUISITIONS LLC
LION POWER SERVICES LLC

By: /s/ Mark Layton
Name: Mark Layton
Title: Chief Financial Officer

[Signatures Continued from Previous Page]

PIRANHA PROPPANT LLC
MAKO ACQUISITIONS LLC
HIGHER POWER ELECTRICAL, LLC
STURGEON ACQUISITIONS LLC
TAYLOR FRAC, LLC
TAYLOR REAL ESTATE INVESTMENTS, LLC
SOUTH RIVER ROAD, LLC
STINGRAY ENERGY SERVICES LLC
STINGRAY CEMENTING LLC
5 STAR ELECTRIC, LLC
DIRE WOLF ENERGY SERVICES LLC
MAMMOTH EQUIPMENT LEASING II LLC
BISON SAND LOGISTICS LLC
TIGER SHARK LOGISTICS LLC
WOLVERINE SAND LLC
ANACONDA MANUFACTURING LLC
BLACK MAMBA ENERGY LLC
STINGRAY CEMENTING AND ACIDIZING LLC
AQUAHAWK ENERGY LLC
AQUAWOLF LLC
IVORY FREIGHT SOLUTIONS LLC
ORCA ENERGY SERVICES LLC
SEAWOLF ENERGY SERVICES LLC
SILVERBACK LOGISTICS LLC
IFX TRANSPORT LLC
PYTHON EQUIPMENT LLC
FALCON FIBER SOLUTIONS LLC
PREDATOR AVIATION LLC

By: /s/ Mark Layton
Name: Mark Layton
Title: Chief Financial Officer

[Signatures Continued from Previous Page]

Acknowledged and Agreed:

PNC BANK, NATIONAL ASSOCIATION,
as Lender and as Agent

By: /s/ Ron Zeiber
Name: Ron Zeiber
Title: Senior Vice President

Commitment Percentage: 54.054054%
Commitment Amount: $64,864,864.86

BARCLAYS BANK PLC,
as a Lender
By: /s/ Sydney G. Dennis
Name: Sydney G. Dennis
Title: Director

Commitment Percentage: 18.918919%
Commitment Amount: $22,702,702.70

CREDIT SUISSE AG, Cayman Islands Branch,
as a Lender

By: /s/ Ranjit Lakhanpal
Name: Ranjit Lakhanpal
Title: Authorized Signatory

By: /s/ Lawrence Park
Name: Lawrence Park
Title: Authorized Signatory

Commitment Percentage: 13.513514%
Commitment Amount: $16,216,216.22

[Signatures Continued on Next Page]

[Signatures Continued from Previous Page]

Acknowledged and Agreed:

UMB BANK, N.A.,
as a Lender

By: /s/ Thomas J. Zeigler
Name: Thomas J. Zeigler
Title: Senior Vice President

Commitment Percentage: 13.513514%
Commitment Amount: $16,216,216.22

EXHIBIT 21.1

Mammoth Energy Services, Inc.
List of Significant Subsidiaries

Name of Subsidiary
5 Star Electric LLC
Air Rescue Systems Corporation
Anaconda Manufacturing LLC
Aquahawk Energy LLC
Aquawolf LLC
Barracuda Logistics LLC
Bison Drilling and Field Services LLC
Bison Sand Logistics LLC
Bison Trucking LLC
Black Mamba Energy LLC
Cobra Acquisitions LLC
Cobra Aviation LLC
Lion Power Services LLC
Dire Wolf Energy Services LLC
Great White Sand Tiger Lodging Ltd.
Higher Power Electrical LLC
IFX Transport LLC
Ivory Freight Solutions LLC
Leopard Aviation LLC
Mako Acquisitions LLC
Mammoth Energy Partners LLC
Mammoth Equipment Leasing LLC
Mr. Inspections LLC
Muskie Proppant LLC
Panther Drilling Systems LLC
Piranha Proppant LLC
Predator Aviation LLC
Python Equipment LLC
Redback Coil Tubing LLC
Redback Energy Services LLC
Redback Pumpdown Services LLC
Stingray Cementing and Acidizing LLC
Silverback Energy LLC
South River Road LLC
Stingray Cementing LLC
Stingray Energy Services LLC
Stingray Pressure Pumping LLC
Sturgeon Acquisitions LLC
Taylor Frac LLC
Taylor Real Estate Investments LLC
Tiger Shark Logistics LLC
White Wing Tubular Services LLC
WTL Oil LLC

EXHIBIT 23.1

CONSENT OF JOHN T. BOYD COMPANY

John T. Boyd Company, in connection with the annual report on Form 10-K of Mammoth Energy Services. Inc. and any amendments or supplements and/or exhibits thereto (collectively, the “Form 10-K”), consents to:

- the filing and use of the technical report summary titled “Technical Report Summary, Frac Sand Resources and Reserves, Piranha and Taylor Mines” (the “Technical Report”) dated February 28, 2022, as an exhibit to and referenced in the Form 10-K;
- the use of and references to our firm name, including our status as an expert or “qualified person” (as defined in Subpart 1300 of Regulation S-K promulgated by the Securities and Exchange Commission), in connection with the Form 10-K and any such Technical Report; and
- the information derived, summarized, quoted or referenced from the Technical Report, or portions thereof, that was prepared by us, that we supervised the preparation of and/or that was reviewed and approved by us, that is included or incorporated by reference in the Form 10-K.

We hereby further consent to the incorporation by reference in the Registration Statements on form S-8 (No. 333-217361) and Form S-3 (No. 333-257186), of Mammoth Energy Services, Inc. of the Technical Report and the information referenced above.

Respectfully submitted,

JOHN T. BOYD COMPANY

By: /s/ Authorized Person
Name: Authorized Person
Title: Authorized Officer

March 4, 2022

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 4, 2022, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Mammoth Energy Services, Inc. on Form 10-K for the year ended December 31, 2021. We consent to the incorporation by reference of said reports in the Registration Statements of Mammoth Energy Services, Inc. on Form S-3 (File No. 333-257186) and on Form S-8 (File No. 333-217361).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 4, 2022

EXHIBIT 31.1

CERTIFICATIONS

I, Arty Straehla, Chief Executive Officer, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Arty Straehla

Arty Straehla

Chief Executive Officer

March 4, 2022

EXHIBIT 31.2

CERTIFICATIONS

I, Mark Layton, Chief Financial Officer, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Mark Layton

Mark Layton

Chief Financial Officer

March 4, 2022

EXHIBIT 32.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the “Company”) for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Arty Straehla, as Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”); and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Arty Straehla

Arty Straehla
Chief Executive Officer
March 4, 2022

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section. This certification shall not be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

EXHIBIT 32.2

**CERTIFICATION OF THE CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the "Company") for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark Layton, as Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"); and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Mark Layton

Mark Layton
Chief Financial Officer
March 4, 2022

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section. This certification shall not be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

Mine Safety Disclosure

The following disclosures are provided pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") and Item 104 of Regulation S-K, which requires certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate mines regulated under the Federal Mine Safety and Health Act of 1977 (the "Mine Act").

Mine Safety Information. Whenever the Federal Mine Safety and Health Administration ("MSHA") believes a violation of the Mine Act, any health or safety standard or any regulation has occurred, it may issue a citation which describes the alleged violation and fixes a time within which the U.S. mining operator must abate the alleged violation. In some situations, such as when MSHA believes that conditions pose a hazard to miners, MSHA may issue an order removing miners from the area of the mine affected by the condition until the alleged hazards are corrected. When MSHA issues a citation or order, it generally proposes a civil penalty, or fine, as a result of the alleged violation, that the operator is ordered to pay. Citations and orders can be contested and appealed, and as part of that process, are often reduced in severity and amount, and are sometimes dismissed. The number of citations, orders and proposed assessments vary depending on the size and type (underground or surface) of the mine as well as by the MSHA inspector(s) assigned.

Mine Safety Data. The following provides additional information about references used in the table below to describe the categories of violations, orders or citations issued by MSHA under the Mine Act:

- Section 104 S&S Citations: Citations received from MSHA under section 104 of the Mine Act for violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of a mine safety or health hazard.
- Section 104(b) Orders: Orders issued by MSHA under section 104(b) of the Mine Act, which represents a failure to abate a citation under section 104(a) within the period of time prescribed by MSHA. This results in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.
- Section 104(d) Citations and Orders: Citations and orders issued by MSHA under section 104(d) of the Mine Act for unwarrantable failure to comply with mandatory health or safety standards.
- Section 110(b)(2) Violations: Flagrant violations issued by MSHA under section 110(b)(2) of the Mine Act.
- Section 107(a) Orders: Orders issued by MSHA under section 107(a) of the Mine Act for situations in which MSHA determined an "imminent danger" (as defined by MSHA) existed.

The following table details the violations, citations and orders issued to us by MSHA during the year ended December 31, 2021:

Mine[(a)]	**Section 104 S&S Citations(#)**	**Section104(b)Orders (#)**	**Section104(d)Citations and Orders(#)**	**Section 110(b)(2) Violations(#)**	**Section107(a)Orders (#)**	**Proposed Assessments[(b)]($, amounts in dollars)**	**Mining Related Fatalities (#)**
Taylor, WI	1	—	—	—	—	$ 125	—
Menomonie, WI	—	—	—	—	—	$ —	—
New Auburn, WI	—	—	—	—	—	$ —	—

a. The definition of mine under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting minerals, such as land, structures, facilities, equipment, machines, tools and minerals preparation facilities. Unless otherwise indicated, any of these other items associated with a single mine have been aggregated in the totals for that mine. MSHA assigns an identification number to each mine and may or may not assign separate identification numbers to related facilities such as preparation facilities. We are providing the information in the table by mine rather than MSHA identification number because that is how we manage and operate our mining business and we believe this presentation will be more useful to investors than providing information based on MSHA identification numbers.

b. Represents the total dollar value of proposed assessments from MSHA under the Mine Act relating to any type of citation or order issued during the year ended December 31, 2021.

Pattern or Potential Pattern of Violations. During the year ended December 31, 2021, none of the mines operated by us received written notice from MSHA of (a) a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of mine health or safety hazards under section

104(e) of the Mine Act or (b) the potential to have such a pattern.

Pending Legal Actions. There were no legal actions pending before the Federal Mine Safety and Health Review Commission (the Commission) as of December 31, 2021. The Commission is an independent adjudicative agency established by the Mine Act that provides administrative trial and appellate review of legal disputes arising under the Mine Act.

TECHNICAL REPORT SUMMARY
FRAC SAND RESOURCES AND RESERVES
PIRANHA AND TAYLOR MINES

Barron and Jackson Counties, Wisconsin

Prepared For

MAMMOTH ENERGY SERVICES

By

John T. Boyd Company

Mining and Geological Consultants

Pittsburgh, Pennsylvania, USA

Report No. 3756.007

FEBRUARY 2022

John T. Boyd Company

Mining and Geological Consultants

Chairman
James W. Boyd

President and CEO
John T. Boyd II

Managing Director and COO
Ronald L. Lewis

Vice Presidents
Robert J. Farmer
Matthew E. Robb
John L. Weiss
Michael F. Wick
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Managing Director - Australia
George Cumplido

Managing Director - China
Jisheng (Jason) Han

Managing Director – South America
Carlos F. Barrera

Managing Director – Metals
Gregory B. Sparks

Pittsburgh
4000 Town Center Boulevard, Suite 300
Canonsburg, PA 15317
(724) 873-4400
(724) 873-4401 Fax
jtboydp@jtboyd.com

Denver
(303) 293-8988
jtboydd@jtboyd.com

Brisbane
61 7 3232-5000
jtboydau@jtboyd.com

Beijing
86 10 6500-5854
jtboydcn@jtboyd.com

Bogota
+57-3115382113
jtboydcol@jtboyd.com

www.jtboyd.com

February 28, 2022
File: 3756.007

Mammoth Energy Services
4727 Gaillardia Parkway, Suite 200
Oklahoma City, OK 73142

Attention: Mr. Mark Layton
Chief Financial Officer

Subject: Technical Report Summary
Frac Sand Resources and Reserves
Piranha and Taylor Mines
Barron and Jackson Counties, Wisconsin

Dear Mr. Layton:

This Subpart 1300 and Item 601(b)(96) of the US Securities and Exchange Commission's (SEC) Regulation S-K-compliant (S-K 1300) technical report summary provides the results of John T. Boyd Company's (BOYD) independent estimate of the frac (proppant) sand resources and reserves for Mammoth Energy Services' (Mammoth) Piranha and Taylor mines as of December 31, 2021.

We wish to acknowledge the cooperation of Mammoths' management and staff for providing the technical, financial, and legal information used in completing this project. Our findings are based on BOYD's extensive experience in preparing frac sand resource and reserve estimates used in SEC filings, and our knowledge of frac sand mining in Wisconsin and throughout North America.

Respectfully submitted,

JOHN T. BOYD COMPANY
By:

John T. Boyd II
President and CEO

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GLOSSARY OF ABBREVIATIONS AND DEFINITIONS

$	:	US dollar(s)
%	:	Percent or percentage
Mammoth	:	Mammoth Energy Services
amsl	:	Above mean sea level
API	:	American Petroleum Institute
BOYD	:	John T. Boyd Company
CapEx	:	Capital expenditures
COGS	:	Cost of goods sold
Constant Dollar	:	A monetary measure that is not influenced by inflation and used to compare time periods. Sometimes referred to as "real dollars".
CY	:	Cubic yards
DCF	:	Discounted Cash Flow
Discount Rate	:	A rate of return used to discount future cash flows based on the return investors expect to receive from their investment.
DUC	:	Drilled but uncompleted gas or oil well.
FOB	:	Free-on-Board
Frac Sand	:	Frac sand is a naturally occurring, high silica content quartz sand, with grains that are generally well rounded and exhibit high compressive strength characteristics relative to other silica sand. It is utilized as a prop or "proppant" in unconventional shale frac well completions.
Frac Sand Resource	:	Frac sand resource is a concentration or occurrence of sand material of economic interest in or on the Earth's crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as quality specifications, likely mining dimensions, location or continuity, that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.
Frac Sand Reserve	:	Frac sand reserve is an estimate of tonnage and grade or quality of mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More

GLOSSARY OF ABBREVIATIONS AND DEFINITIONS - Continued

		specifically, it is the economically mineable part of a mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.
Indicated Sand Resource	:	An Indicated Sand Resource is that part of a Sand Resource for which quantity, grade or quality, densities, shape, and physical characteristics are estimated with sufficient confidence to allow the application of Modifying Factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Geological evidence is derived from adequately detailed and reliable exploration, sampling and testing, and is sufficient to assume geological and grade or quality continuity between points of observation. An Indicated Sand Resource has a lower level of confidence than that applying to a Measured Sand Resource and may only be converted to a Probable Sand Reserve.
IRR	:	Internal rate-of-return
ISO	:	International Organization for Standardization
lb	:	Pound
LOM	:	Life-of-Mine
Measured Sand Resource	:	A Measured Sand Resource is that part of a Sand Resource for which quantity, grade or quality, densities, shape, and physical characteristics are estimated with confidence sufficient to allow the application of Modifying Factors to support detailed mine planning and final evaluation of the economic viability of the deposit. Geological evidence is derived from detailed and reliable exploration, sampling, and testing and is sufficient to confirm geological and grade or quality continuity between points of observation. A Measured Sand Resource has a higher level of confidence than that applying to either an Indicated Sand Resource or an Inferred Sand Resource. It may be converted to a Proven Sand Reserve or to a Probable Sand Reserve.
Mesh	:	A measurement of particle size often used in determining the size distribution of granular material.
Mineral Reserve	:	*See "Frac Sand Reserve"*
Mineral Resource	:	*See "Frac Sand Resource"*
Modifying Factors	:	The factors that a qualified person must apply to indicated and measured sand resources and then evaluate to establish the economic viability of sand reserves. A qualified person must apply and evaluate modifying factors to convert measured and indicated resources to proven and probable reserves. These factors include,

GLOSSARY OF ABBREVIATIONS AND DEFINITIONS - Continued

	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.
MSHA	: Mine Safety and Health Administration. A division of the U.S. Department of Labor.
msl	: Mean sea level
NOAA	: National Oceanic and Atmospheric Administration
NSR	: New Source Review
NTU	: Nephelometric turbidity units
NPV	: Net Present Value
NWS	: Northern White Sands
PCF	: Pounds per cubic foot
Probable Sand Reserve	: A Probable Sand Reserve is the economically mineable part of an Indicated and, in some circumstances, a Measured Sand Resource. The confidence in the Modifying Factors applying to a Probable Sand Reserve is lower than that applying to a Proven Sand Reserve.
Proppant Sand	: See "Frac Sand"
Proven Sand Reserve	: A Proven Mineral Reserve is the economically mineable part of a Measured Sand Resource. A Proven Sand Reserve implies a high degree of confidence in the Modifying Factors.
PSI	: Pounds per square inch
ROM	: Run-of-Mine. The as-mined including in-seam clay partings mined with the sand, and out-of-seam dilution.
SEC	: U.S. Securities and Exchange Commission
S-K 1300	: Subpart 1300 and Item 601(b)(96) of the U.S. Securities and Exchange Commission's Regulation S-K
Surficial	: Relating to the earths surface or the geology that is on the surface.

GLOSSARY OF ABBREVIATIONS AND DEFINITIONS - Continued

Ton	:	Short Ton. A unit of weight equal to 2,000 pounds
tph	:	Tons per Hour
tpy	:	Tons per Year
WTI	:	West Texas Intermediate

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1.0 EXECUTIVE SUMMARY

1.1 Introduction

BOYD was retained by Mammoth to complete an independent technical audit of mineral resource and mineral reserve estimates—hereafter referred to as frac sand resource and frac sand reserve estimates—for their active mining operations located near Taylor, Wisconsin (the "Taylor Mine") and New Auburn, Wisconsin (the "Piranha Mine"). Throughout the report, the Taylor and Piranha mines may also be referred to as the Taylor and Piranha "operations", "plants", "properties", or "facilities". This report summarizes the results of our reserve estimate and audit and satisfies the requirements for Mammoths' disclosure of frac sand resources and reserves set forth in S-K 1300.

BOYD's findings are based on our detailed examination of the supporting geologic, technical, and economic information obtained from: (1) Mammoth provided files, (2) discussions with Mammoth personnel, (3) records on file with regulatory agencies, (4) public sources, and (5) nonconfidential BOYD files. Our investigation was performed to obtain reasonable assurance that Mammoth's frac sand resource and reserve statements are free from material misstatement. This report provides an independent estimate of the frac sand resources and reserves underlying the Taylor and Piranha controlled properties.

This chapter provides a summary of primary information contained within this technical report summary and is supported by remaining portions of this report including text, figures, and tables. Weights and measurements are expressed in US customary units. Unless noted, the effective date of the information, including estimates of frac sand reserves, is December 31, 2021.

1.2 Property Description and Control

Mammoth owns and operates two Northern White frac sand (NWS) operations in Wisconsin. BOYD has been involved with the Piranha Property (formerly Chieftain Sand's New Auburn operation) since 2014, and with the Taylor Property since 2014. Prior to this S-K 1300 report for the subject properties, BOYD prepared resource and reserve reports and associated updates as well as other reports related to these properties.

The Piranha surface frac sand mining and wet processing operation is located on a contiguous block of acres controlled by Mammoth, in Baron County, Wisconsin. The subject property is approximately 5 miles northwest of the town of New Auburn. The

Piranha Dry Plant and Loadout is also located in Baron County and is approximately 1.25 miles east of the mine and wet processing facility. The Piranha frac sand products are predominantly shipped on the Union Pacific railway.

The Taylor Mine surface frac sand mining operation is located on a contiguous block of acres controlled by Mammoth, in Jackson County, Wisconsin. The subject property is less than 1 mile northwest of the town of Taylor. Taylor's Rail Loadout, located in Trempealeau County, Wisconsin, is approximately 2.3 miles southwest of the mine and processing facility. The Taylor frac sand products are predominantly shipped on the Canadian National Railway.

The general location of both mines is provided in Figure 1.1, following this page.

1.3 Geology

NWS deposits are generally located in the north-central portion of the United States (predominantly in Minnesota, Wisconsin, and Illinois, with lesser amounts in Arkansas and Iowa). NWS is found in poorly cemented Cambrian and Ordovician sandstones and in unconsolidated alluvial deposits locally derived from these sandstones. The Saint Peter, Jordan, Wonewoc, and Mount Simon formations, located in south-central Minnesota into Wisconsin, are the primary sources of NWS, and can be observed in Figure 4.1, which presents the various stratigraphic rock units in Wisconsin.

Both the Piranha and Taylor operations are underlain by the Wonewoc Formation, one of the most extensively mined frac sand deposits in Wisconsin. The Wonewoc Formation is of Cambrian Age and consists of two members: the overlying Ironton Member and the underlying Galesville Member. Both members are typically white, well sorted, subrounded to rounded orthoquartzites that typically exhibit a monocrystalline grain structure lending to the high compressive strength these sands exhibit in lab testing. The Wonewoc sand formation is well accepted and has a "branding" distinction recognized by many of the well service companies in many of the energy basins.

The sandstone underlying the Piranha Property is a relatively uniform deposit of the Wonewoc Formation. Small areas of glacial tills are present in eastern portions of the property where glacial processes have scoured out portions of the Wonewoc sandstone. Drill hole coverage and previous mining activities on the property have helped define

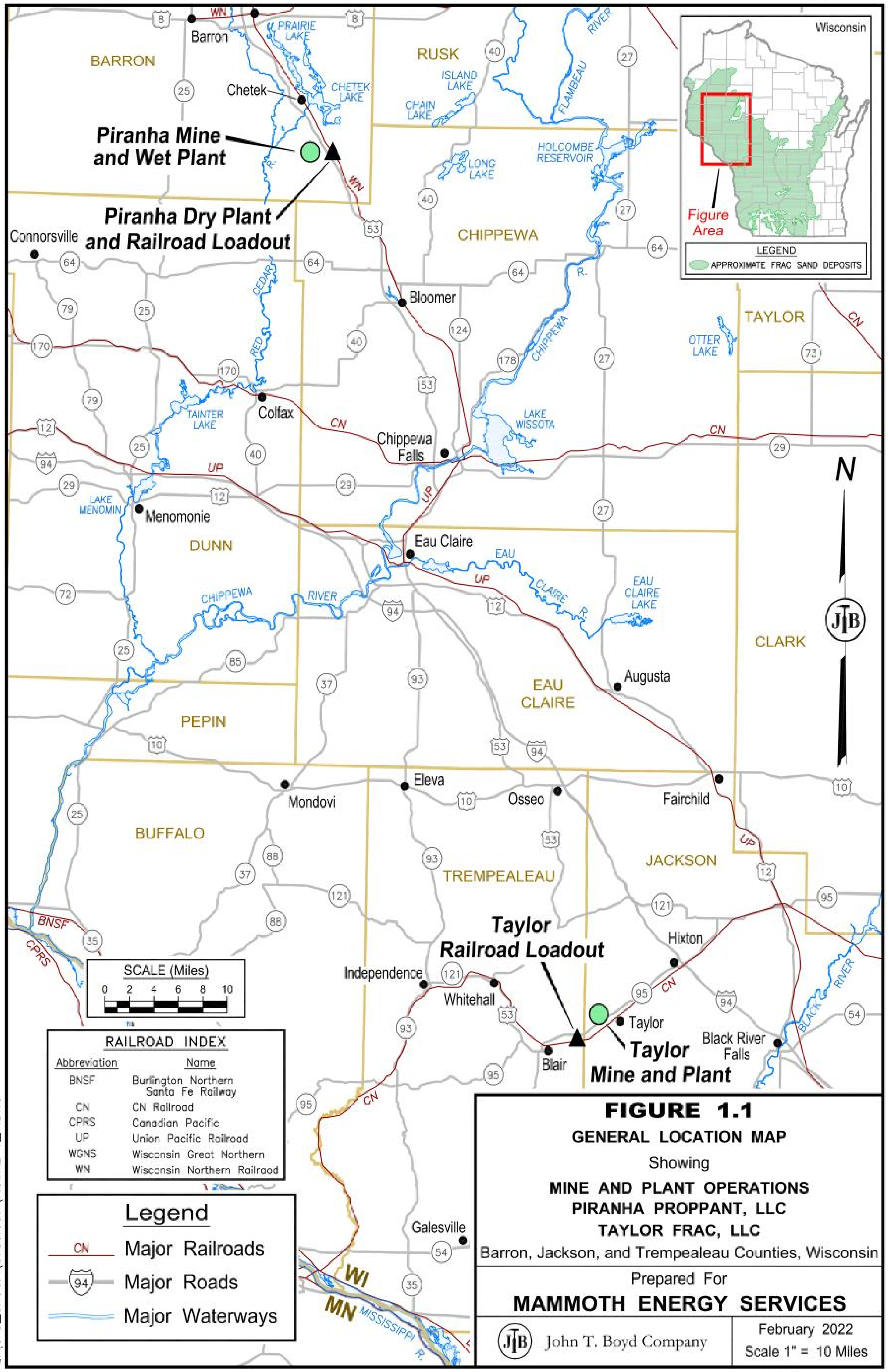

FIGURE 1.1

GENERAL LOCATION MAP

Showing

MINE AND PLANT OPERATIONS
PIRANHA PROPPANT, LLC
TAYLOR FRAC, LLC
Barron, Jackson, and Trempealeau Counties, Wisconsin

Prepared For

MAMMOTH ENERGY SERVICES

Q:\CAD_GROUP\3756.007\FIGURE 1_1.DWG

approximate extents of these areas of thin or absent sand. Based on drilling results, the deposit ranges in thickness from around 30 ft in the eastern-most extents of the property, to more than 90 ft in central portions of the property. The average mineable thickness is estimated to be approximately 65 ft across the subject area.

The Taylor property consists of the Taylor area and the Miller property. On the Taylor area, the sand ranges in thickness from 11 ft near the outcrops to 177 ft beneath the highest ridge areas, and averages 86 ft. On the Miller property, the sand ranges in thickness from 13 ft to 141 ft, and averages 63 ft. The bottom of the mineable material is between elevations of 890 ft and 905 ft above mean sea level (AMSL). In addition, the sand thickness is greatest under the tops of the wooded knoll areas with thinning occurring moving downslope toward the outcrops. Sand grain size becomes coarse in the middle portions of the Galesville interval.

Both operations exhibit overburden in the 0 ft to 30 ft range. This material is initially cleared and stockpiled or moved to area under reclamation.

1.4 Exploration

1.4.1 Piranha

A series of comprehensive drilling and sampling programs have been performed on and around the subject property throughout the history of the operation with the latest occurring in January 2018. A total of 111 drill holes are located on various parcels, which are either owned properties or potential acquisition properties. Prop-Tester Inc., StimLab Inc., FracTAL, LLC., and Minerals Technologies Inc. have analyzed the samples obtained from the various drilling programs on the property.

BOYD reviewed the drilling and sampling results obtained from the various exploration programs, as well as, when available, the equipment utilized, and the sampling, logging, and field work performed. When methodologies and procedures were available for review, the data obtained appeared to be carefully and professionally collected, prepared, and documented in conformance with generally accepted industry standards. BOYD opines that the information provided is adequate for purposes of evaluating and estimating frac sand resources and reserves on the Piranha Property.

1.4.2 Taylor

Two notable exploration drilling and sampling programs have been completed on the Taylor property.

The first program was completed in mid-2011 and consisted of drilling 18 holes on the Taylor area and 11 holes on the Miller Property. The A.F. Gelhar Company performed the drilling as well as the particle size analysis on the samples. A composite sample was collected for API RP19C testing which was performed by Stim-Lab, Inc., Duncan, Oklahoma in April 2012. The specific geologic logs or physical sand samples from this campaign were not available for review, however, a summary of results was included in a third-party consultant report issued in April 2012 by Bay Environmental Strategies, Incorporated (Bay). Based upon our extensive knowledge of the Wonewoc sand formation, BOYD believes the exploration data contained in the Bay report to be representative of the in-place resource.

BOYD notes that the first exploration program was performed during the time when energy markets were predominantly interested in coarse grade proppant sand. Therefore, it appears that the first program focused only on the coarse increment of the Wonewoc Formation. Consequently, the majority of the drill holes were terminated within the Wonewoc Sandstone prior to penetrating the bottom of the formation. As market demand shifted to finer mesh proppant sand products, it became necessary to mine the full thickness of the sand formation in order to recover the finer sand. To gain a complete understanding of the full sand formation being mined would require additional drilling and sampling data.

A second drilling and sampling program commenced in February 2018 and focused only on defining the total thickness of the mineable sandstone unit (defining the top and bottom occurrences of the mineable sandstone interval) and obtaining additional information on overburden thickness throughout the Taylor area and Miller Property. BOYD selected the drill hole locations, which were generally spaced at approximately 500 ft to 1,000 ft centers, to achieve the stated objectives. PSC Drilling was contracted to drill the holes (Atlas Copco D65 DTH drill rig). Cuttings were logged by a BOYD geologist, and Taylor personnel gathered grab samples from various drilling depths. The sieve analyses were performed by Taylor's in-house labs.

As such, the results of the two drilling programs, associated laboratory testing, and historic operating test data are the principal sources of information used to define the extent, tonnage, and quality of sand underlying the Taylor Property.

1.5 Frac Sand Reserves and Quality

This technical report summary provides an estimate of frac sand reserves for Mammoths' Taylor and Piranha mines in accordance with the requirements set forth in

S-K 1300. These estimates were independently prepared by BOYD utilizing information provided by Mammoth.

BOYD's estimate of frac sand reserves for the Taylor and Piranha mines as of December 31, 2021, total 62 million saleable product (i.e., greater than 140-mesh and less than 20-mesh in size) tons, 24 million tons are underlying the Taylor Property and 38 million tons are underlying the Piranha Property.

Table 1.1 presents the estimated frac sand reserves by product mesh size for the Taylor Property and Table 1.2 presents the estimated sand reserves by product size for the Piranha Property:

Table 1.1: Taylor Reserves as of December 31, 2021

Estimated Reserve Tons By Classification as of December 31, 2021			
Proven Tons (000)			
20/40-Mesh	40/70-Mesh	70/140-Mesh	Total
6,109	11,801	6,367	24,277

Table 1.2: Piranha Reserves as of December 31, 2021

Estimated Reserve Tons By Classification as of December 31, 2021			
Proven Tons (000)			
20/40-Mesh	40/70-Mesh	70/140-Mesh	Total
11,414	20,333	6,067	37,814

Projecting saleable product volumes of approximately 639,000 tons per year, the Taylor Operation has an expected life-of-mine (LOM) of 38 years. Projecting saleable product volumes of approximately 671,000 tons per year, the Piranha Operation has an expected LOM of over 56 years. This longevity only considers the estimated Proven Reserves as shown above.

Concerning the frac sand quality of the properties, PropTester performed API RP-19C/ISO 13503-2 tests on composite samples created from select samples as described below during the drilling programs on the Piranha and Taylor properties. Testing was performed on frac sand products including 20/40-mesh,30/50-mesh, 40/70-mesh, and 100-mesh as described below.

1.5.1 Piranha

API/ISO frac sand characterization is supported by samples composited from seven drill holes spaced across the property. Testing was conducted by PropTester, Inc. laboratories located in Cypress, Texas according to the procedures outlined in ISO 13503-2/API RP19C, Section 11 and API RP 56/58/6. Testing was completed on four anticipated product sizes: 20/40, 30/50, 40/70, and 70/140 (100-Mesh). Each product size had a full suite of API RP 19C testing performed in order to assess the proppant characteristics relative to standard industry specification. Results of the API testing are in Table 1.3 below.

Table 1.3: Piranha API/ISO Test Results

	20/40-Mesh		30/50-Mesh		40/70-Mesh		100-Mesh	
Test	Result	Limit	Result	Limit	Result	Limit	Result	Limit
Roundness	0.8	0.6 ≥	0.7	0.6 ≥	0.7	0.6 ≥	0.7	0.6 ≥
Sphericity	0.8	0.6 ≥	0.8	0.6 ≥	0.8	0.6 ≥	0.8	0.6 ≥
Turbidity (NTU)	5	≤ 250	6	≤ 250	6	≤ 250	15	≤ 250
Acid Solubility (%)	1.5	≤ 2.0	1	≤ 2.0	0.9	≤ 3.0	5	≤ 3.0
K-Value (psi)	6K	-	7K	-	8K	-	8K	-

API/ISO product test results indicate an overall premium NWS proppant material that is typically produced from the Wonewoc Formation. Quality characteristics tend to exceed API recommended minimum specifications. BOYD notes that the Piranha operation has been selling various frac sand sized products their customers.

1.5.2 Taylor

A composite sample split obtained from Taylor's first drilling and sampling program and historic site laboratory data were utilized to demonstrate the quality of the 20/40-mesh, 30/50-mesh, and 40/70-mesh product sizes. Because of the first drilling program's focus on the coarse sand material, 20/70-mesh material, API RP 19C testing was not performed on the 70/140-mesh material. The test results from the suite of 20/70-mesh products are presented in Table 1.4 below.

Table 1.4: Taylor API/ISO Test Results

	20/40-Mesh		30/50-Mesh		40/70-Mesh	
Test	Result	Limit	Result	Limit	Result	Limit
Roundness	0.7	0.6 ≥	0.6	0.6 ≥	0.7	0.6 ≥
Sphericity	0.8	0.6 ≥	0.8	0.6 ≥	0.8	0.6 ≥
Turbidity (NTU)	33	≤ 250	41	≤ 250	55	≤ 250
Acid Solubility (%)	0.6	≤ 2.0	0.8	≤ 2.0	1	≤ 3.0
K-Value (psi)	6K	-	7K	-	9K	-

API/ISO product test results indicate an overall premium NWS proppant material that is typically produced from the Wonewoc Formation. Quality characteristics tend to meet or exceed API recommended minimum specifications. BOYD notes that the Taylor operation has been selling various frac sand sized products to their customers.

1.6 Operations

1.6.1 Mining

The Taylor and the Piranha mines both employ open pit mining as the primary sand extraction method. Most of the mineable area at both locations has between zero and 30-ft of overburden and vegetation that is removed prior to mining the target Wonewoc sand formation. The target friable Wonewoc sandstone material is then drilled and blasted in successive benches. The run-of-mine (ROM) sand material is loaded with front-end loaders into an in-pit crusher/feeder system that conveys the material to a surge hopper prior to being fed into the wet process plant at Taylor. The drilling and blasting of the sand is contracted to a third-party company. At Piranha, the sand is hauled from the face area to the wet plant by articulated truck. At Piranha, this operation is performed by a third-party contractor. After wet processing at Piranha, the wet plant product is hauled by highway truck to the dry process plant/loadout approximately 1.5 miles east of the mine. Both mines operate seasonally from March-April through October-November depending on both weather and material demand.

1.6.2 Processing and Shipping

Both operations have a typical wet process plant, dry process plant, and rail shipping terminal. In addition, both dry process plants and loadouts are open year-round and utilize stockpiled wet plant product from the wet plants during the winter and shoulder months when the mine and wet plants are idle.

<u>1.6.2.1 Taylor</u>

In the wet process plant, the plus 20-mesh oversize will be removed by wet screens and the minus 140-mesh fine waste material will be segregated (and removed) using hydrosizers and cyclones. The plant will employ attrition scrubbers to ensure a low turbidity product free of clusters. The waste stream of fines from the wet plant will be directed to a thickener with the thicken sludge removed and the resultant overflow water routed to ponds for process water recycling. Output from the wet plant is estimated at 250 tons per hour (tph) of feedstock material containing 13% to 15% moisture.

The wet plant product consists of a minus 40-mesh to plus 140-mesh material that is stockpiled. A front-end loader feeds the processed sand into the dry process plant for

drying and finished screening. The dry processing plant consists of two Stark Aire fluid bed dryers, a 100 tph and a 150 tph. Gas to fuel the dryers is supplied via a direct pipeline. The dried product is fed onto eight sets of four-deck Rotex screens. The waste product from the baghouses will be conveyed back to the mine site area for disposal and/or use in reclamation.

The Taylor Process Plant has an estimated process yield of 73%. For every 100 tons of ROM material fed into the wet process plant, approximately 73 tons result in a finished and saleable product following dry processing.

Finished product from the dry plant is stored in 1 of 10 product silos having a combined 18,400 tons of capacity. The final product is weighed then trucked from the product storage silos to the Taylor off-site rail loadout facility. The rail loadout is serviced by the Canadian National Railway. A full suite of dried frac sand products are produced: 20/40-mesh, 30/50-mesh, 40/70-mesh, and 70/140-mesh (100-mesh). The overall nameplate capacity for the operation is approximately 1.8 million tons per year of saleable product.

1.6.2.2 Piranha

At the wet process plant, the ROM sand is classified into a 40/140-mesh material. A series of wet screens, hydrosizers, and cyclones are used to classify the material. The fines waste material is routed to a thickener and belt presses to reclaim process water. The majority of the process water is recycled from the on-site process water ponds. Makeup water is sourced from on-site water wells. The filter cake sludge material is hauled to reclamation areas and mixed with spoil to be used to reclaim the property.

The resultant wet plant stockpile material is trucked approximately 1.5 miles by third-party trucks to the dry process/rail loadout site east of the mine. The material is stockpiled and fed by loader into one of two dry process plants as needed. The material is dried by natural gas fired dryers and screened on multi-deck Rotex screens. Both plants utilize a Carrier 150 tph fluid bed dryer for a combined throughput of 300 tph. Finished product nameplate capacity of the plant is approximately 2.0 million tons per year of finished product.

The Piranha Process Plant has an estimated process yield of 79%. For every 100 tons of ROM material fed into the wet process plant, approximately 79 tons result in a finished and saleable product following dry processing.

Finished products are stored in one of six product storage silos that have a combined storage capacity of 18,000 tons. The silos directly load material into railcars. The predominant products produced at the site are 20/40-mesh, 30/50-mesh, and 40/70-mesh frac sand. Piranha has a circular unit train loadout system. The rail loadout has direct access to the Union Pacific (UP) Railway via the Progressive short line Railroad.

1.6.3 Infrastructure

On-site facilities at each site include a scale house, office, shop, and a quality laboratory located in the dry process plant. The surface facilities currently located at the mine are well constructed and have the necessary capacity/capabilities to support both of the operations.

The Taylor Plant is serviced by Xcel Electric LLC and the Piranha Plant is serviced by Barron Electric Company. Natural gas to both operations is supplied by line natural gas by Constellation Gas Company. Plant process water is recycled within both plants and is pumped from freshwater process ponds on-site to the wash plants. Additional makeup water is obtained from on-site water wells if needed.

1.7 Financial Analysis

1.7.1 Market Analysis

The frac sand market appears to be set for recovery in 2022. After several years of depressed pricing and volume, activity in all basins show signs of a meaningful uptick. In Western Canada the expectation is an increase of 20%-35% in total volume, much of that focused on the first quarter of 2022. In tandem, West Texas has already reached a fever pitch with reports of many companies not getting their sand needs met, and reports of price increases as high as 20%. This has led to conversations around bringing NWS volumes back to the Permian Basin for the first time in several years.

On pricing, recently US Silica announced a pricing increase on sand sold up to 10% in January. Anecdotally, prices of $20-$30 per ton for 40/70 spot sand have started to receive traction for volumes shipped on the railroad in Wisconsin. Furthermore, the demand for ancillary grades, such as 20/40 and 30/50, have started to tick up. This is resulting in elevated pricing on all grades, not just 40/70.

One mitigating factor impacting overall availability is the current labor shortage in the United States. Many plants are reporting difficulty bringing on new talent which is causing many plants to fall short of their volume potential.

Specifically concerning the Taylor and Piranha plants, Taylor ships sand through their CN rail loadout and Piranha ships sand though their UP loadout. The ability to ship on both of these mainline railways essentially allows Mammoth to participate in all of the energy basins. We cannot practically review all of the basins in order to provide examples of in-basin activity. For this reason, we have chosen to review the Permian, by far the bellwether for the entire North American unconventional energy industry and a large customer of the Piranha operation. Additionally, the Appalachian Basin and Niobrara Basins, are smaller, but indicate activity for the CN railway or customers of the Taylor operation. Generally, activity in the Permian is often a leading indicator of trends in all of the North American Basins including Canada.

1.7.1.1 Permian Basin

Permit submissions for horizontal oil and gas wells in the Permian Basin indicate a continuation of strong drilling ahead. Utilizing data from Baker Hughes and The Railroad Commission of Texas (RRC of TX), the total number of permits filed per average annual working rig for 2021 is tracking at multi-year highs as evidenced in the chart below. For calendar year 2021, there was a total of 4,413 permit submissions with an average 227 horizontal rigs active in the Permian Basin (ratio of 19.5).

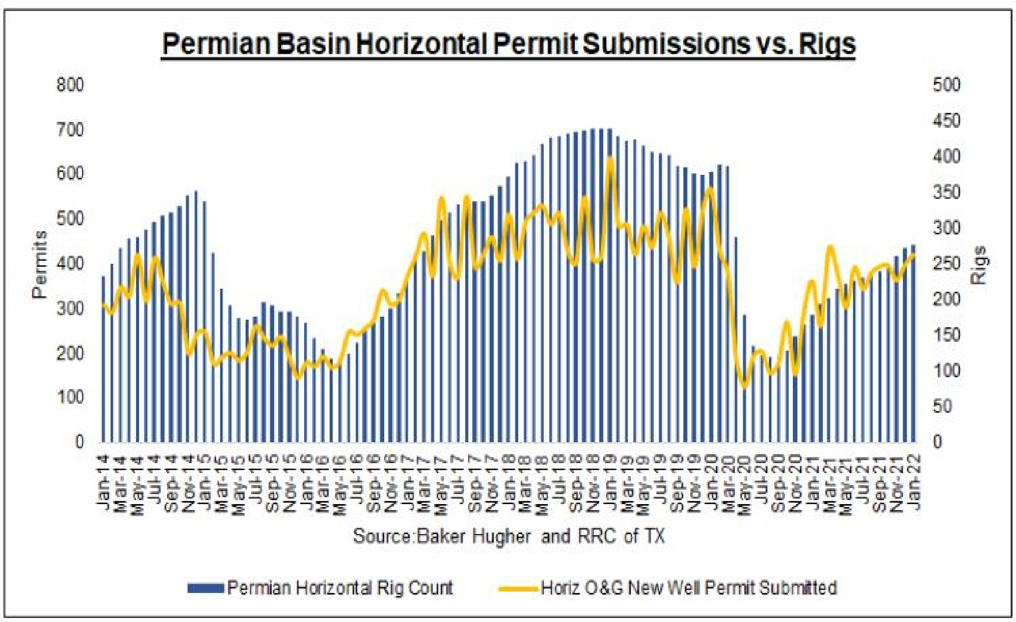

Figure 1.2: Permian Basin HZ Permit Submissions vs. Rigs

Rig counts in the Permian Basin are up approximately 64% as of year-end 2021 versus 2020. This has led to increased production for both crude oil and natural gas. Over the same time-period, crude oil production (barrels per day) and natural gas production (thousand cubic feet per day) in the Permian Basin are up 13% and 16%, respectively.

Both Permian Basin daily crude oil production and daily natural gas production continue to exceed pre-pandemic peaks and reach new records. As of year-end 2021, crude oil production in the basin is nearly 5.0 million barrels per day while basin natural gas production stands at 19.8 billion cubic feet per day.

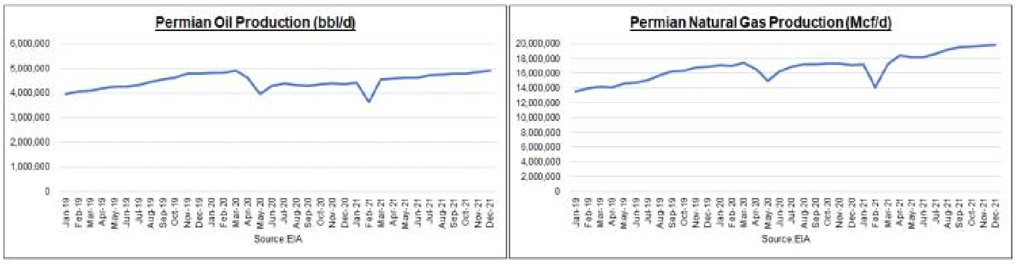

Figure 1.3: Permian Oil Production and Natural Gas Production

1.7.1.2 Appalachian Basin (Marcellus/Utica Play) and Niobrara Basin

Although smaller in size than the Permian energy fields, the Appalachian and Niobrara (or Niobrara-DJ) basins are substantial natural gas and oil plays in North America. Unlike the Permian, the Appalachian and Niobrara import the vast majority of the frac sand, as very few, notable in-basin sand operations exist. The Taylor Mine is advantaged, transportation wise to the Appalachian and Niobrara basins and there are few substitutes for its NWS products.

Following the energy downturn in 2019 and then Covid shutdown in 2020, the basin wellfield activity appears to be rebounding. Horizontal rigs have stabilized over the past two years as can be seen on Figure 1.4, but gas production per rig is substantially higher. Energy companies are drilling longer laterals and optimizing each well pad

becoming more efficient from a cost perspective and overall natural gas production is stable as can be seen from Figure 1.5.

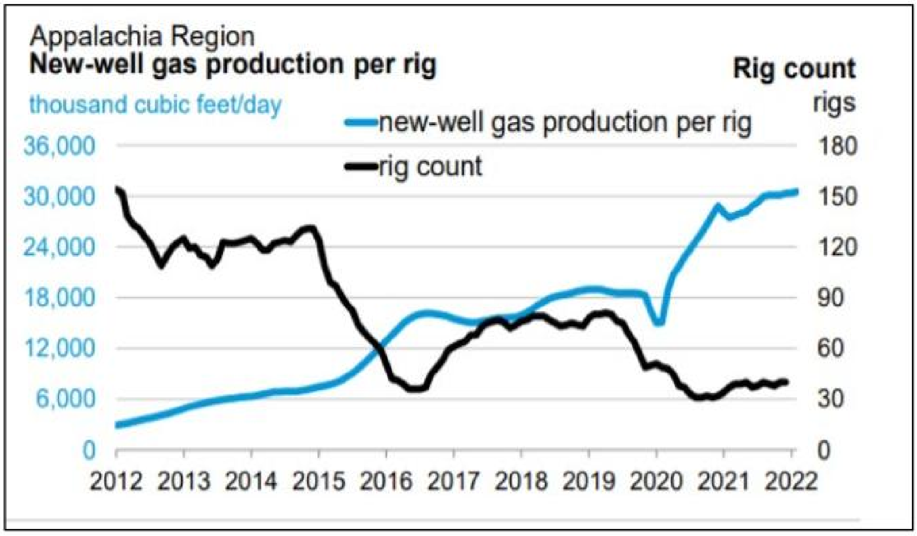

Figure 1.4: Appalachian Rig Count and Production per Rig (Source: EIA)

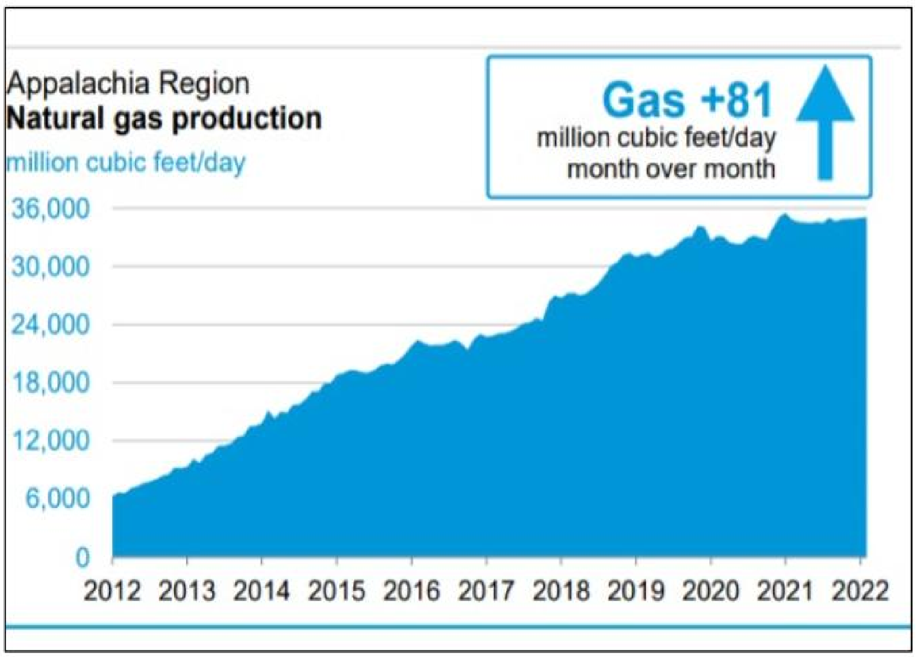

Figure 1.5: Appalachian Gas Production (Source: EIA)

Similarly, the DJ basin has seen a rebound in rig count since the Covid shutdown. Both gas and oil rig counts have risen but productivity per well has decreased as can be seen in Figure 1.6.

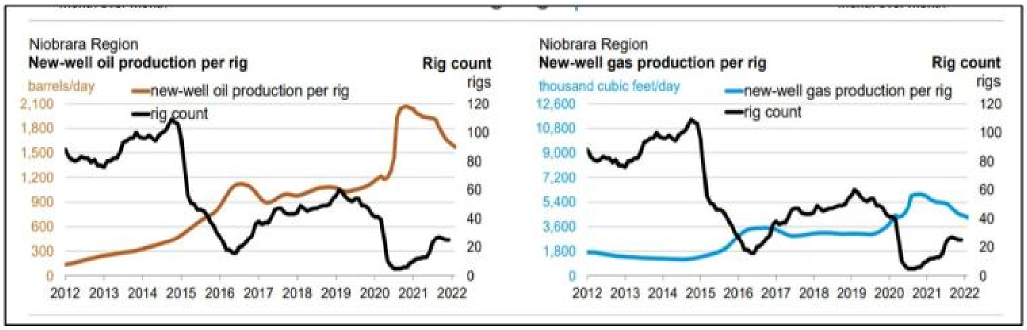

Figure 1.6: Niobrara Oil and Gas Rig Count and Productivity (Source: EIA)

Overall gas and oil production remains relatively flat in the basin, but more wells are being drilled to maintain this capacity. Figure 1.7 illustrates the overall yearly gas and oil production in the basin.

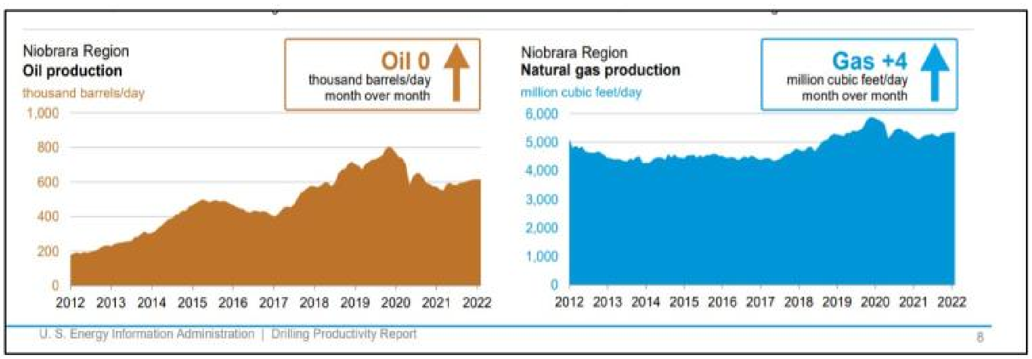

Figure 1.7: Niobrara Oil and Gas Production (Source: EIA)

Having survived the challenging environment of 2019 and 2020, Mammoth's operations should continue to prove viable into the future notwithstanding a sustained and significant energy price collapse. Their low-cost mining scheme, advantaged transport to select basins, and high-quality product help to create an advantage compared with other NWS producers.

1.7.2 Sales, Production, and Cost Forecast

1.7.2.1 Piranha

Table 1.5 below, presents frac sand production, sales and cost projections for the period 2022 through 2026.

Table 1.5: Piranha Production Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
ROM Production (000)	853	853	853	853	853
Wet Plant Feed	853	853	853	853	853
Processing Recovery (%)	82.8	82.8	82.8	82.8	82.8
Wet Plant Product	706	706	706	706	706
Dry Plant Feed	706	706	706	706	706
Processing Recovery (%)	95.0	95.0	95.0	95.0	95.0
Dry Plant Product	671	671	671	671	671

Annual forecasted ROM production is based on the dry plant producing 671,000 tons per year of saleable product after a processing (wet and dry processing plant) loss of approximately 21%, as discussed in Chapter 6. Forecasted dry processing plant production is within the operation's current infrastructure capacities and capabilities.

The dry processing plant is projected to produce a product mix of approximately 84% for 20/70-mesh products and approximately 16% for 70/140-mesh (100-mesh) product. The percent split is based on the product tons by mesh size for the frac sand reserves discussed in Chapter 5.

The sales price forecasts, by product, in Table 1.6 are based on price projections provided by Mammoth. Piranha's short-term sales volume forecast did not include 100-mesh sales. BOYD projected that 100-mesh sales would begin in Year 2024 and ramp up from 11,000 tons per year to 107,000 tons per year by Year 2029, which represents 100% of the 100-mesh dry plant product. We opine that these volumes and prices are reasonable projections.

Table 1.6: Piranha Sales Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Tons Sold (000)	564	564	575	585	607
20/70-Mesh	564	564	564	564	564
70/140-Mesh (100-Mesh)	-	-	11	21	43
Revenues ($000)	10,485	10,485	10,650	10,800	11,130
Product Pricing ($ per ton sold)					
Weighted Average Price	18.59	18.59	18.52	18.46	18.34
20/70-Mesh	18.59	18.59	18.59	18.59	18.59
70/140-Mesh (100-Mesh)	-	-	15.00	15.00	15.00

Table 1.7 below, presents the above table's cost projections on a cost per ton sold basis for the period 2022 through 2026.

Table 1.7: Piranha Annual $ per Ton Sold Cash Cost Projections

	Summary Cash Cost of Goods Sold ($ per ton sold)				
	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Cash Operating Expense	15.17	15.17	14.88	14.64	14.12
Royalty	0.12	0.12	0.13	0.13	0.13
SG&A	2.18	2.18	2.14	2.11	2.03
Final Reclamation Escrow	0.04	0.04	0.04	0.04	0.04
Total Cash Cost of Goods Sold	17.51	17.51	17.19	16.92	16.32

Mammoth provided BOYD with their projected sustaining CapEx, for Years 2022 and 2023. Post Year 2023 sustaining CapEx for Piranha was projected by BOYD to be $0.75 per ton sold.

1.7.2.2 Taylor

Table 1.8 below, presents frac sand production and sales projections for the period 2022 through 2026.

Table 1.8: Taylor Production Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
ROM Production (000)	875	875	875	875	875
Wet Plant Feed	875	875	875	875	875
Processing Recovery (%)	76.8	76.8	76.8	76.8	76.8
Wet Plant Product	673	673	673	673	673
Dry Plant Feed	673	673	673	673	673
Processing Recovery (%)	95.0	95.0	95.0	95.0	95.0
Dry Plant Product	639	639	639	639	639

Annual forecasted ROM production is based on the dry plant producing 639,000 tons per year of saleable product after a processing (wet and dry processing plant) loss of approximately 27%, as discussed in Chapter 6. Forecasted dry processing plant production is within the operation's current infrastructure capacities and capabilities.

The dry processing plant is projected to produce a product mix of approximately 74% for 20/70-mesh products and approximately 26% for 100-mesh product. The percent split is based on the product tons by mesh size for the frac sand reserves discussed in Chapter 5.

The sales price forecasts, by product, in Table 1.9 are based on price projections provided by Mammoth. Taylor's short-term sales volume forecast included reduced 100-mesh sales. BOYD projected that 100-mesh sales would ramp up from 61,000 tons per year in Year 2022 to 167,000 tons per year by Year 2029, which represents 100% of the 100-mesh dry plant product. We opine that these volumes and prices are reasonable projections.

Table 1.9: Taylor Sales Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Tons Sold (000)	533	533	539	539	564
20/70-Mesh	472	472	472	472	472
70/140-Mesh (100-Mesh)	61	61	67	67	92
Revenues ($000)	10,515	10,515	10,605	10,605	10,980
Product Pricing ($ per ton sold)					
Weighted Average Price	19.73	19.73	19.68	19.68	19.47
20/70-Mesh	20.34	20.34	20.34	20.34	20.34
70/140-Mesh (100-Mesh)	15.00	15.00	15.00	15.00	15.00

Table 1.10 below, presents the above table's cost projections on a cost per ton sold basis for the period 2022 through 2026.

Table 1.10: Taylor Annual $ per Ton Sold Cash Cost Projections

	Summary Cash Cost of Goods Sold ($ per ton sold)				
	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Cash Operating Expense	13.03	13.03	12.92	12.92	12.44
SG&A	3.27	3.27	3.23	3.23	3.09
Final Reclamation Escrow	0.09	0.09	0.09	0.09	0.09
Total Cash Cost of Goods Sold	16.39	16.39	16.24	16.24	15.62

Mammoth provided BOYD with their projected sustaining CapEx, for Years 2022 and 2023. Post Year 2023 sustaining CapEx for Taylor was projected by BOYD to be $0.80 per ton sold.

1.7.3 Economic Analysis

The net present value (NPV) estimate was made for purposes of confirming the general economic viability of the reported frac sand reserves and not for purposes of valuing Mammoth or its assets. Internal rate-of-return (IRR) and project payback were not calculated, as there was no initial investment considered in the financial model. All values are as of January 1, 2022, for both operations. The intent of this exercise is to demonstrate that the operations generate positive cash flows (based on a 12% discount rate), on a pre-tax and after-tax basis, that supports the statement of frac sand reserves herein.

1.7.3.1 Piranha

BOYD prepared an economic analysis, as of January 1, 2022, for the Piranha Operation using the production, sales, and financial projections presented in this report. Our analysis confirms that the operation generates positive cash flows (based on a 12% discount rate), on a pre-tax and after-tax basis, that supports the statement of frac sand reserves herein.

Table 1.11 below presents the pre-tax cash flow projections based on the proposed LOM production schedule and revenue, cash cost of goods sold, and CapEx and other estimates discussed above for the Piranha operation.

Table 1.11: Summary Pre-Tax Cash Flow Statement

	Summary Cash Flow Statement ($ 000)						
	2022 to 2031	2032 to 2041	2042 to 2051	2052 to 2061	2062 to 2071	2072 to 2078	Total
Total Tons Sold (000)	6,186	6,710	6,710	6,710	6,710	4,264	37,290
Revenues	113,038	120,898	120,898	120,898	120,898	76,755	673,383
COGS	99,407	99,889	99,493	99,828	100,164	64,876	562,396
CapEx	4,191	5,033	5,033	5,033	5,033	2,768	27,089
Net Pre-Tax Cash Flow	9,440	15,977	16,372	16,037	15,701	9,111	83,898

Discounted Cash Flow-Net Present Values (DCF-NPV) on a pre-tax and after-tax basis, using discount rates of 10%, 12%, and 15%, were calculated utilizing the cash flows above. The DCF-NPV values used mid-year discounting and all cash flows were on a constant dollar basis.

The pre-tax DCF-NPV ranges from approximately $6.9 million to $11.8 million. The after-tax DCF-NPVs were all positive. Table 1.12 summarizes the results of the pre-tax analyses:

Table 1.12: DCF-NPV

	DCF-NPV ($ 000)		
	10%	12%	15%
Pre-Tax	11,760	9,310	6,899

Refer to Table 12.3 for the detailed LOM cash flow analysis and corresponding pre-tax DCF-NPV analyses at a 12% discount rate.

1.7.3.2 Taylor

BOYD prepared an economic analysis, as of January 1, 2022, for the Taylor Operation using the production, sales, and financial projections presented in this report. Our analysis confirms that the operation generates positive cash flows (based on a 12% discount rate), on a pre-tax and after-tax basis, that supports the statement of frac sand reserves herein.

Table 1.13 below presents the pre-tax cash flow projections based on the proposed LOM production schedule and revenue, cash cost of goods sold, and CapEx and other estimates discussed above for the Taylor operation.

Table 1.13: Summary Pre-Tax Cash Flow Statement

	Summary Cash Flow Statement ($ 000)				
	2022 to 2031	2032 to 2041	2042 to 2051	2052 to 2059	Total
Total Tons Sold (000)	5,828	6,390	6,390	5,107	23,715
Revenues	112,625	121,055	121,055	96,747	451,482
COGS	88,563	90,225	90,545	72,647	341,979
CapEx	7,393	5,112	5,112	3,323	20,939
Net Pre-Tax Cash Flow	16,670	25,718	25,398	20,778	88,563

DCF-NPV on a pre-tax and after-tax basis, using discount rates of 10%, 12%, and 15%, were calculated utilizing the cash flows above. The DCF-NPV values used mid-year discounting and all cash flows were on a constant dollar basis.

The pre-tax DCF-NPV ranges from approximately $11.5 million to $18.8 million. The after-tax DCF-NPVs were all positive. Table 1.14 summarizes the results of the pre-tax analyses:

Table 1.14: DCF-NPV

	DCF-NPV ($ 000)		
	10%	12%	15%
Pre-Tax	18,827	15,221	11,507

Refer to Table 12.9 in Chapter 12 for the detailed LOM cash flow analysis and corresponding pre-tax DCF-NPV analyses at a 12% discount rate.

1.8 Regulation and Liabilities

The Piranha Mine's operations are predominantly regulated by a Barron County, Wisconsin non-metallic reclamation permit which contains detailed reclamation plans for the property. Mine operators must submit annual reports to Barron County containing information on the reclamation status of their mines and pay annual fees based on the disturbed acres. They must also provide written certification that the reclamation plan is being followed. A reclamation bond is also required, and the amount is periodically updated based on the number of disturbed acres.

The Taylor Mine in Jackson County has requirements similar to those described above for mining and reclamation. The Jackson County Zoning, Planning and POWTS Department administers the mining program.

Air emissions for both sites are regulated by the Wisconsin Department of Natural Resources, Bureau of Air Management. Mammoth monitors air emissions at both sites and has current permits.

Based on our review of information provided by Mammoth and available public information, it is BOYD's opinion that Mammoth's record of compliance with applicable mining, water quality, and environmental regulations is generally typical for the industry. BOYD is not aware of any regulatory violation or compliance issue that would materially impact the frac sand reserve estimate.

1.9 Conclusions

It is BOYD's overall conclusion that Mammoth's frac sand reserves, as reported herein: (1) were prepared in conformance with accepted industry standards and practices, and (2) are reasonably and appropriately supported by technical evaluations, which consider all relevant modifying factors. We do not believe there is other relevant data or information material to the properties that would render this technical report summary misleading. Our findings and conclusions represent only informed professional judgment.

Given the operating history and actual performance of Mammoth through the COVID-19 pandemic and volatile energy market conditions, we consider the going concern to be viable under the current and foreseeable operating environment. A general assessment of risk is presented in the relevant sections of this report.

The ability of Mammoth, or any mine operator, to recover all of the reported frac sand reserves is dependent on numerous factors that are beyond the control of, and cannot be anticipated by, BOYD. These factors include mining and geologic conditions, the capabilities of management and employees, the securing of required approvals and

permits in a timely manner, future sand prices, etc. Unforeseen changes in regulations could also impact performance. Opinions presented in this report apply to the site conditions and features as they existed at the time of BOYD's investigations and those reasonably foreseeable.

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2.0 INTRODUCTION

2.1 Registrant and Purpose

This technical report summary was prepared for Mammoth in support of their disclosure of frac sand reserves for the Piranha and Taylor mines in accordance with S-K 1300.

Mammoth is a public (TUSK), US-based energy services company headquartered in Oklahoma City, Oklahoma. Mammoth is an integrated company serving both the electric utility and the oil and gas industries in North America and US territories. Mammoth's subsidiaries provide a diversified set of drilling and completion services to the exploration and production industry including, among others, pressure pumping, natural sand and proppant services as well as trucking, directional drilling, rentals and water transfer. In addition, Mammoth's infrastructure division provides transmission, distribution and logistics services to various public and private owned utilities throughout the United States. Mammoth acquired both of their frac sand operations, the Taylor Mine and the Piranha Mine (formerly Chieftain Sand's New Auburn operation), in 2017. Additional information is available on their website at mammothenergy.com.

2.2 Terms of Reference

Mammoth retained BOYD to complete an independent technical assessment of frac sand resources and reserves for both the Piranha and Taylor Mines. Our objective was to: (1) review and evaluate the scientific and technical information on which the frac sand resources and reserves are based, and (2) update our independently-prepared estimates of frac sand resources and reserves for the subject properties.

We have previously prepared estimates of fracs and resources and reserves for each of Mammoth's mining properties. Our initial Taylor Resource and Reserve Report was issued in February 2018 (BOYD Report No. 3756.001). The initial Piranha Resource and Reserve Report was issued in May 2017 (BOYD Report No. 3828.001). Additionally, BOYD had completed technical studies of the Piranha operation for the previous owners, Chieftain.

The estimates of frac sand resources and reserves reported herein have been adjusted to reflect an effective (i.e., "as of") date of December 31, 2021.

The results of our assessment, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in S-K 1300. The purpose of this report is threefold: (1) to summarize available information for the subject mining properties, (2) to provide the conclusions of our independent technical assessment, and (3) to provide a statement of frac sand resources and reserves for the Piranha and Taylor mines. This is the first technical report summary filed by Mammoth for the mines.

BOYD's findings are based on our detailed examination of the supporting geologic, technical, and economic information provided by Mammoth in formulating the estimates of frac sand resources and reserves disclosed in this report. We independently estimated the frac sand resources and reserves from first principles based on third-party exploration information provided to BOYD. We used standard engineering and geoscience methods, or a combination of methods, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of mining property evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The ability of Mammoth, or any mine operator, to recover all of the estimated frac sand reserves presented in this report is dependent on numerous factors that are beyond the control of, and cannot be anticipated by, BOYD. These factors include mining and geologic conditions, the capabilities of management and employees, the securing of required approvals and permits in a timely manner, future sand prices, etc. Unforeseen changes in regulations could also impact performance. Opinions presented in this report apply to the site conditions and features as they existed at the time of BOYD's investigations and those reasonably foreseeable.

This report is intended for use by Mammoth subject to the terms and conditions of its engagement agreement with BOYD. The agreement permits Mammoth to file this report as a technical report summary with the SEC pursuant to S-K 1300. Except for the purposes legislated under US securities law, any other uses of or reliance on this report by any third party is at that party's sole risk. The responsibility for this disclosure remains with Mammoth. The user of this document should ensure that this is the most recent disclosure of frac sand resources and reserves for the Piranha and Taylor mines as it is no longer valid if more recent estimates have been issued.

2.3 Expert Qualifications

BOYD is an independent consulting firm specializing in mining-related engineering and financial consulting services. Since 1943, BOYD has completed over 4,000 projects in the United States and more than 90 other countries. Our full-time staff comprises mining experts in: civil, environmental, geotechnical, and mining engineering; geology; mineral economics; and market analysis. Our extensive experience in frac sand resources/reserve estimation and our knowledge of the subject property, provides BOYD an informed basis on which to opine on the frac sand reserves available at the Mammoth mines. An overview of BOYD can be found on our website at www.jtboyd.com.

The individuals primarily responsible for this audit and the preparation of this report are by virtue of their education, experience, and professional association considered qualified persons as defined in S-K 1300. Neither BOYD nor its staff employed in the preparation of this report have any beneficial interest in Mammoth, and are not insiders, associates, or affiliates of Mammoth. The results of our resource/reserve estimate and subsequent audit were not dependent upon any prior agreements concerning the conclusions to be reached, nor were there any undisclosed understandings concerning any future business dealings between Mammoth and BOYD. This report was prepared in return for fees based upon agreed commercial rates, and the payment for our services was not contingent upon our opinions regarding the project or approval of our work by Mammoth and its representatives.

2.4 Principal Sources of Information

Information used in this assignment was obtained from: (1) Mammoth files and plans, (2) discussions with Mammoth personnel, (3) records on file with regulatory agencies, (4) public sources, and (5) nonconfidential BOYD files. The primary basis for this report is the previous technical reports, BOYD Reports No. 3828.001 issued in May 2017, and No. 3756.003 issued in April 2018, which provided independently-prepared estimates of frac sand resources and reserves for the Piranha Mine and BOYD Reports No. 3756.001 issued in February 2018, and No. 3756.004 issued in January 2019, which provided independently-prepared frac sand resource and reserve estimates for the Taylor Mine.

Additional information was provided by Mammoth including:

- Financial forecasting models.
- Historical information, including:
  - Production reports and reconciliation statements.
  - Financial statements.

- Product sales and pricing.
- Mine plans.
- Site plans.
- Operational data.

The data and work papers used in the preparation of this report are on file in our offices.

2.4.1 Site Visits

Recent personal inspections of the Piranha and Taylor operations were not made for purposes of compiling this report. We have made multiple trips to both the Piranha and Taylor operations over the past five years. We also provide Mammoth with a year-end frac sand reserve statements for each operation that incorporate any material changes to the operations including property/lease/reserve acquisitions or dispositions. BOYD is thoroughly familiar with both of the subject Mammoth operations.

2.4.2 Reliance on Information Provided by the Registrant

In the preparation of this report we have relied, without independent verification, upon information furnished by Mammoth with respect to: property interests; exploration results; current and historical production from such properties; current and historical costs of operation and production; and agreements relating to current and future operations and sale of production.

BOYD exercised due care in reviewing the information provided by Mammoth within the scope of our expertise and experience (which is in technical and financial mining issues) and concluded the data are valid and appropriate considering the status of the subject properties and the purpose for which this report was prepared. BOYD is not qualified to provide findings of a legal or accounting nature. We have no reason to believe that any material facts have been withheld, or that further analysis may reveal additional material information. However, the accuracy of the results and conclusions of this report are reliant on the accuracy of the information provided by Mammoth.

While we are not responsible for any material omissions in the information provided for use in this report, we do not disclaim responsibility for the disclosure of information contained herein which is within the realm of our expertise.

2.5 Effective Date

The estimates of frac sand resources and reserves presented in this technical report summary are effective as of December 31, 2021. The report effective date is December 31, 2021.

2.6 Units of Measure

The US customary measurement system has been used throughout this report. Tons are short tons of 2,000 pounds-mass. Unless otherwise stated, all currency is expressed in constant 2021 US Dollars ($).

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3.0 PROPERTY OVERVIEW

3.1 Description and Location

Referring to Figure 1.1 (General Location Map), the Piranha and Taylor operations are approximately 70 miles apart. From the Piranha wet plant site, it is approximately a 100-mile drive southeast to reach the Taylor operation.

3.1.1 Piranha Operation

Mammoth's Piranha Mine surface frac sand mining and wet processing operation is located on a contiguous block of land controlled by Mammoth, in Baron County, Wisconsin. The subject property is approximately 5 miles northwest of the town of New Auburn. Piranha's Dry Plant and Loadout is also located in Baron County and is approximately 1.25 miles east of the mine and wet processing facility.

Geographically, the Piranha frac sand processing plant is located at approximately 45°15'30.84" N latitude and 91°38'13.05" W longitude, and the dry plant/loadout is at approximately 45°15'18.82" N latitude and 91°36'12.39" W longitude. Figure 1.1 illustrates the location of the Piranha Sand Mine/Wet Plant Property and the Dry Plant/Railroad Loadout.

3.1.2 Taylor Operation

Mammoth's Taylor Mine surface frac sand mining operation is located on a contiguous block of land controlled by Mammoth, in Jackson County, Wisconsin. The subject property is less than 1 mile northwest of the town of Taylor. Taylor's Rail Loadout, located in Trempealeau County, Wisconsin, is approximately 2.3 miles southwest of the mine and processing facility.

Geographically, the Taylor frac sand processing plant is located at approximately 44°19'46.23" N latitude and 91°8'23.77" W longitude. and the off-site rail loadout is at approximately 44°18'14.96" N latitude and 91°10'34.86" W longitude. Figure 1.1 illustrates the location of the Taylor Mine and Plant and the off-site Rail Loadout.

3.2 History

3.2.1 Piranha Operation

The Mammoth's Piranha Operation was acquired from Chieftain Sand and Proppant LLC (Chieftain) on May 26, 2017. Under Chieftain, the property commenced mining operations in August 2012. In January 2018, Mammoth purchased the Conoboy tract, which is adjacent to a tract of land previously mined by Chieftain. Operations on the Piranha/Chieftain property have mined premium NWS for use in the oil/gas industry.

Mammoth's Mine Safety and Health Administration (MSHA) identification number (4703665), for the mine/wet processing operation, was originally assigned in 2012 and transferred to Mammoth in May 2017. The MSHA identification number (4703675), for the dry plant/loadout facility, was originally assigned in 2012, and transferred to Mammoth on May 2017.

3.2.2 Taylor Operation

The Taylor Operation commenced mining operations in 2012 and has mined premium NWS for use in the oil/gas industry. Mammoth acquired the Taylor operation in June 2017 when they acquired Sturgeon Acquisitions, LLC. The mining operations were issued a MSHA identification number (4703655) in June 2012.

3.3 Property Control

Ownership information, provided to BOYD by Mammoth for the Piranha and Taylor operations, has been accepted as being true and accurate for the purpose of this report.

3.3.1 Piranha Operation

The Piranha Property comprises approximately 600 acres, where Mammoth owns 100% of the surface and mineral rights. The current estimated mineable area is approximately 313 acres, or 52% of the total property, after observing setbacks, right of ways, processing areas, and other non-mining acreage.

3.3.2 Taylor Operation

Taylor owns in fee numerous land parcels which comprise the process plant site, mineral resource areas, and rail loadout facility. There are two areas, consisting of numerous parcels, which comprise the mining property. These two areas are the Taylor area and the Miller property, collectively referred to as the Taylor Property.

The Taylor area consists of 11 contiguous land parcels totaling approximately 391 acres. Current mining and processing operations occur on this property and approximately 148 acres of frac sand resources remain in this area. These parcels are zoned for mineral extraction and retain a current Nonmetallic Mining Permit issued by Jackson County.

The Miller Property, which is located adjacent to and southwest of the Taylor area, is comprised of five parcels totaling approximately 60 acres. No mining has occurred on this property; however, it is estimated to contain 43 mineable acres. Currently, the property is not permitted for mining activities, however, BOYD notes that it is reasonable to assume that this permit would be granted at such time Taylor submits the permit application.

3.4 Adjacent Properties

Wisconsin frac sand mining and processing activity occurs in three general regions/districts: the Barron, Blair, and Oakdale districts. All three districts have seen extensive mining of the sand deposits for purposes of producing frac sand.

Mammoth's Piranha operation is in the Barron district, where existing frac sand mining operations are located west-southwest of the Piranha Mine. The Taylor operation is in the Blair district, with existing frac sand mining operations located west-southwest of the Taylor Mine.

3.5 Regulation and Liabilities

Mining and related activities for the Piranha and Taylor operations are regulated by Federal, State of Wisconsin, and Local/County agencies.

3.6 Accessibility, Local Resources, and Infrastructure

3.6.1 Piranha Operation

Mammoth's Piranha Mine is located near a number of towns in western Wisconsin. Barron County and the eight surrounding counties have a combined population of over 356,000 people, according to 2020 population estimates for the State of Wisconsin.

General access to the Piranha's mining and loadout sites is via a well-developed network of primary and secondary roads serviced by state and local governments. These roads offer direct access to the mine and processing facilities and are open year-round. Primary vehicular access to both the mining and loadout sites is via County Road AA, with nearby access to U.S. Highway 53.

The Piranha operation has an off-site rail loadout with access to the UP rail network.

The Piranha operation has access to numerous airports as there are:

- Four International airports within a 285-mile radius of the site.
- Four Domestic airports within a 135-mile radius of the site.
- Three Local airports within a 60-mile radius of the site.

Sources of three phase electrical power, natural gas, and other miscellaneous materials are readily available. Water is supplied to the operation via various sources such as, on-site wells, on-site ponds, and public water.

3.6.2 Taylor Operation

Mammoth's Taylor Mine is located near a number of towns in southwestern Wisconsin. Jackson County and the seven surrounding counties have a combined population of over 455,000 people, according to 2020 population estimates for the State of Wisconsin.

General access to the Taylor Mine is via a well-developed network of primary and secondary roads serviced by state and local governments. These roads offer direct access to the operation and are open year-round. Primary vehicular access to both sites is via State Route 95.

Taylor's off-site rail loadout has access to the CN rail network.

The Taylor operation has access to numerous airports as there are:

- Four International airports within a 255-mile radius of the site.
- Four Domestic airports within a 155-mile radius of the site.
- Three Local airports within a 70-mile radius of the site.

Sources of three phase electrical power, natural gas, and other miscellaneous materials are readily available. Water is supplied to the operation via various sources such as, on-site wells, on-site ponds, and public water.

3.7 Physiography

3.7.1 Piranha Operation

The Piranha Operation is in the Central Plain region, a geographical region approximately 13,000 square miles in area, which is in the shape of V across the central part of Wisconsin (Burnett and Polk Counties on the western border of the state, down to Columbia County, and up to Marinette County on the eastern border of the state). The region is characterized as a flat sandy plain with elevations between 700 ft and 800 ft above sea level; however, the western part of the Central Plain region does have some hilly areas where elevations reach as high as 1,200 ft above sea level (e.g., in Barron County).

The surface topography within the Piranha Property is fairly flat lying. The property is overlain by glacial till ranging from a few feet to about 38 ft in depth. Beneath the glacial till is a relatively uniform deposit of the Wonewoc Formation, one of the primary sources of NWS. Wonewoc sand is present over most of the property, with the exception of certain areas where glacial till material is encountered as part or all of the Wonewoc sand unit was eroded. These till areas seem to be isolated and fairly well-defined based on prior exploration and mining activity.

3.7.2 Taylor Operation

The Taylor Operation is located in the Western Upland, a geographical region that comprises the western half of Wisconsin. The Western Upland region is rugged and hilly and is divided by streams and rivers. The region contains numerous rocky outcrops and small caves.

The surface of Taylor's two areas consists of unconsolidated soil, underlain by shale or shaley-sand, which ranges in thickness from 1 ft to 30 ft on the Taylor area, and ranges in thickness from 0 ft to 21 ft on the Miller Property. The frac sand deposit underlying these two areas consists primarily of the Galesville Member of the Wonewoc Formation. Extensive outcropping of this sand is present throughout the area due to high topographic relief.

3.8 Climate

3.6.1 Piranha Property

For the Piranha operation, average monthly high temperatures range from 23°F to 81°F, with June, July, and August being the hottest months. Average monthly low temperatures range from 7°F to 60°F, with the months of November, December, January, February, and March exhibiting average lows at or below freezing (32°F).

Average annual rainfall is 43.5 in. with approximately 78 days of rain. Average annual snowfall is about 52 in. with approximately 27 days of snowfall.

Table 3.1 provides National Oceanic and Atmospheric Administration's (NOAA) monthly average climate data for Barron County, Wisconsin.

Table 3.1: Climate Data for Piranha Property Barron County, Wisconsin

Averages	Units	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
High Temp	°F	23	27	40	55	68	77	81	78	70	56	41	27
Low Temp	°F	7	8	22	34	46	56	60	58	50	38	27	13
Rainfall	inches	0.9	0.8	1.6	2.7	3.4	4.1	3.8	4.4	3.7	2.9	1.8	1.2
	days	5	3	5	7	8	9	8	8	8	7	5	5
Snowfall	inches	11.2	9.3	9.3	3.3	0.3	0.0	0.0	0.0	0.0	0.7	5.7	11.8
	days	7	5	3	2	0	0	0	0	0	0	3	6

Source: National Oceanic and Atmospheric Administration

3.6.1 Taylor Property

For the Taylor operation, average monthly high temperatures range from 23°F to 84°F, with June, July, and August being the hottest months. Average monthly low temperatures range from 7°F to 60°F, with the months of November, December, January, February, and March exhibiting average lows at or below freezing (32°F).

Average annual rainfall is 43.5 in. with approximately 98 days of rain. Average annual snowfall is about 33 in. with approximately 16 days of snowfall.

Table 3.2 provides NOAA's monthly average climate data for Jackson County, Wisconsin.

Table 3.2: Climate Data for Taylor Property Jackson County, Wisconsin

Averages	Units	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
High Temp	°F	23	30	45	58	70	78	84	81	73	59	45	31
Low Temp	°F	7	9	23	34	46	56	60	58	48	37	27	15
Rainfall	inches	1.3	1.4	1.9	4.9	5.0	6.3	4.8	5.4	4.2	4.2	1.6	2.5
	days	6	6	6	11	11	11	8	9	8	9	5	8
Snowfall	inches	7.5	7.6	5.1	2.8	0.0	0.0	0.0	0.0	0.0	0.0	1.2	9.0
	days	4	4	2	1	0	0	0	0	0	0	1	4

Source: National Oceanic and Atmospheric Administration

4.0 GEOLOGY

4.1 Regional Geology

NWS deposits are generally located in the north-central portion of the United States (predominantly in Minnesota, Wisconsin, and Illinois, with lesser amounts in Arkansas and Iowa). NWS is found in poorly cemented Cambrian and Ordovician sandstones and in unconsolidated alluvial deposits locally derived from these sandstones. The Saint Peter, Jordan, Wonewoc, and Mount Simon formations, located in south-central Minnesota into Wisconsin, are the primary sources of NWS, and can be observed in Figure 4.1, on the following page, which presents the various stratigraphic rock units in Wisconsin.

Both the Piranha and Taylor operations are underlain by the Wonewoc Formation, one of the most extensively mined sources of frac sand in Wisconsin. The Wonewoc Formation is of Cambrian age and consists of two members: the overlying Ironton Member and the underlying Galesville Member. Both members are typically white in color, well sorted, subrounded to rounded orthoquartzites that typically exhibit a monocrystalline grain structure lending to the high compressive strength these sands exhibit in lab testing. The Wonewoc frac sand is well accepted and has a "branding" distinction recognized by many of the well service companies in many of the energy basins.

4.2 Local Stratigraphy

4.2.1 Piranha Operation

The sandstone underlying the Piranha Property is a relatively uniform deposit of the Wonewoc Formation. Small areas of glacial tills are present in eastern portions of the property where glacial processes have scoured out portions of the Wonewoc sandstone. Drill hole coverage and previous mining activities on the property have helped define approximate extents of these areas of thin or absent sand.

Based on drilling results, the deposit ranges in thickness from around 30 ft in the eastern-most extents of the property, to more than 90 ft in central portions of the property. The average mineable thickness is estimated to be approximately 65 ft across the subject area. It is noteworthy that a portion of exploration drilling done to date has not fully penetrated through the entire Wonewoc sandstone interval. Much of the drilling

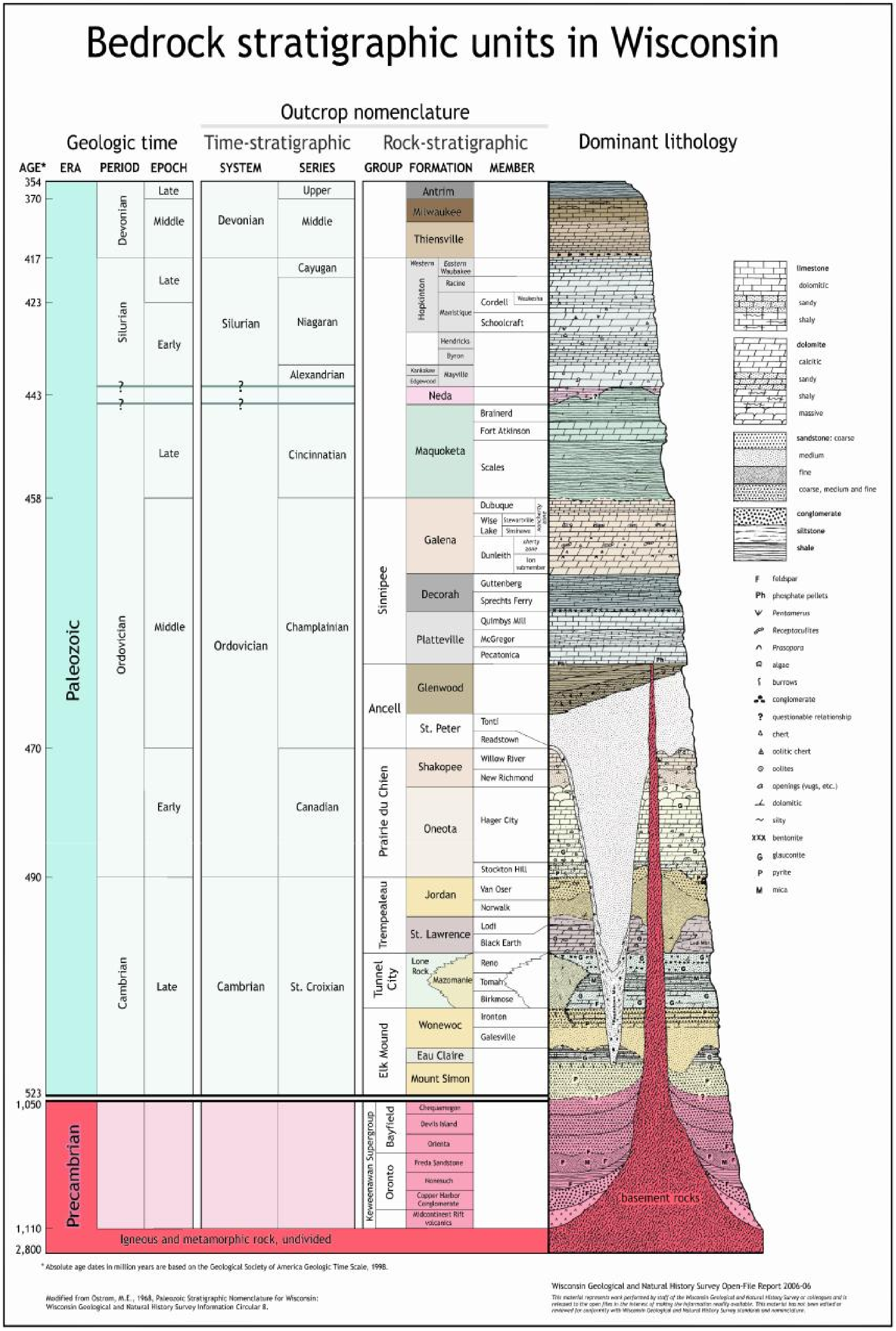

FIGURE 4.1

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work completed in the past was terminated shortly after reaching the elevation of local groundwater assuming that to be the limit of future mining. Regulatory agencies now approve mining permits which allow mining to extend below the ground water table (while still expressly prohibiting dewatering). Since some of the earlier drilling data lacks information on portions of deeper mineable materials, the full thickness of the sand cannot be determined in some areas. For purposes of this report, mineable sand is considered to extend below the ground water level to depths assumed to be within reach of excavating equipment currently on the property. Mine planning assumes mining is done in phases with the upper sand zone (Wonewoc A) mined from the top of the formation to a base elevation of 1,110 ft, leaving a 5-ft interval intact above the local groundwater elevation. The lower mineable interval, Wonewoc B, extends approximately 15 ft into the groundwater table or to a maximum depth of 20 ft below the previous bench or to an elevation of 1,090 ft.

4.2.2 Taylor Operation

The surface of the Taylor Property consists of unconsolidated soil, underlain by shale or shaley-sand. The overburden thickness in the Taylor area ranges 1 ft to 30 ft, with an average of 10 ft, and on the Miller Property ranges 0 ft to 21 ft, with an average of 6 ft. The overburden is shallow in areas near the sand outcrop. In areas under the highest topography, the overburden may become more competent.

Beneath the overburden is the Wonewoc Formation. On the Taylor area, the sand ranges in thickness from 11 ft near the outcrops to 177 ft beneath the highest ridge areas, and averages 86 ft. On the Miller Property, the sand ranges in thickness from 13 ft to 141 ft, and averages 63 ft. The bottom of the mineable material is between elevations of 890 ft and 905 ft above sea level. In addition, the sand thickness is greatest under the tops of the wooded knoll areas with thinning occurring moving downslope toward the outcrops. Sand grain size becomes coarse in the middle portions of the Galesville interval.

4.3 Frac Sand Geology

Frac sand is a naturally occurring, high silica content quartz sand, with grains that are generally well-rounded. The main difference between frac sand and other sands is that frac sand grains are relatively pure in composition, consisting almost entirely of quartz; other sands have numerous impurities that may be cemented to the quartz grains. The pure quartz composition of frac sand grains, along with being well-rounded and spherical in shape, gives these sands the characteristics (crush strength, high acid solubility, low turbidity) that are sought after by the drilling service industry.

The NWS of the Wonewoc Formation is generally characterized by a high silica content, high roundness and sphericity, white color, and lack of deleterious material. Because of their monocrystalline structure, these sands have superior grain strength when compared to other silica sands.

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5.0 EXPLORATION DATA

5.1 Background

BOYD has performed various technical studies, including the estimation of frac sand resources and reserves, for the Piranha Property (formerly Chieftain Sand's New Auburn operation) since 2014, and for the Taylor operation since 2014.

5.2 Exploration Procedures

5.2.1 Drilling and Sampling

5.2.1.1 Piranha

A series of comprehensive drilling and sampling programs have been performed on and around the subject Piranha Property throughout the history of the operation with the latest occurring in January 2018. A total of 111 drill holes are located on various parcels, which are either owned by Mammoth or potential acquisition properties. Prop-Tester Inc., StimLab Inc., FracTAL, LLC., and Minerals Technologies Inc. have analyzed the samples obtained from the various drilling programs on the subject property.

BOYD reviewed the drilling and sampling results obtained from the various exploration programs, as well as, when available, the equipment utilized, and the sampling, logging, and field work performed. When methodologies and procedures were available for review, the data obtained appeared to be carefully and professionally collected, prepared, and documented in conformance with generally accepted industry standards. BOYD opines that the exploration information provided is adequate for purposes of evaluating and estimating frac sand resources and reserves on the Piranha Property.

5.2.1.2 Taylor

Two notable exploration drilling and sampling programs have been completed on the Taylor area and Miller Property.

The first program was completed in mid-2011 and consisted of drilling 18 holes on the Taylor area and 11 holes on the Miller Property. The A.F. Gelhar Company performed the drilling as well as the particle size analysis on the samples. A composite sample was collected for API RP19C testing which was performed by Stim-Lab, Inc., Duncan, Oklahoma in April 2012. The specific geologic logs or physical sand samples from this campaign were not available for review, however, a summary of results was included in the Bay report issued in April 2012. Based upon our extensive knowledge of the

Wonewoc sand formation, BOYD believes the exploration data contained in the Bay report to be representative of the in-place resource.

Sampling during the 2011 program was typically completed on 10-ft increments; however, none of the holes were continuously sampled from the top of the sandstone through the total depth of each hole. With the continuous nature of the Wonewoc sandstone deposition, ongoing production sampling of the sand, and additional nearby exploration information from this formation, BOYD opines that the data gathered was adequate to provide a reasonable understanding of the deposit underlying the Taylor Property.

BOYD notes that the first exploration program was performed during the time when energy markets were predominantly interested in coarse grade proppant sand. As such, it appears that the first program focused only on the coarse increment of the Wonewoc Formation. Consequently, the majority of the drill holes were terminated within the Wonewoc Sandstone prior to penetrating the bottom of the formation. As market demand shifted to finer mesh proppant sand products, it became necessary to mine the full thickness of the sand formation in order to recover the finer sand. To gain a complete understanding of the full sand formation being mined would require additional drilling and sampling data.

A second drilling and sampling program commenced in February 2018 and focused only on defining the total thickness of the mineable sandstone unit (i.e., defining the top and bottom occurrences of the mineable sandstone interval) and obtaining additional information on overburden thickness throughout the Taylor Property (Taylor area and Miller Property). BOYD selected the drill hole locations, which were generally spaced at approximately 500 ft to 1,000 ft centers, to support the estimation of frac sand resources. PSC Drilling was contracted to drill the holes. Cuttings were logged by a BOYD geologist, and Taylor personnel gathered grab samples from various drilling depths. The sieve analyses were performed by Taylor's in-house labs.

BOYD notes that the results of the two drilling programs, associated laboratory testing, and historic operating test data are the principal sources of information used to define the extent, tonnage, and quality of sand underlying the Taylor Property.

5.2.2 Frac Sand Quality Testing

5.2.2.1 Piranha

The Piranha operation has produced premium quality NWS products throughout its operating history. Exploration drilling records, sieve analyses, and API/ISO testing show the deposit to be capable of continuing to supply premium quality NWS product.

Results from the various API tests performed on the samples from the Piranha Property are discussed in Section 5.3.

5.2.2.2 Taylor

A review of the available drill hole analysis indicates the Taylor Property is underlain by a NWS grade sand deposit that is predominately fine to coarse in grain size. Test results are indicative of (consistent with) high quality NWS mined and processed from the Wonewoc Formation in this area of Wisconsin. In addition, the operation has produced premium quality NWS products throughout its operating history.

Results from the various API tests performed on the samples from the Taylor Property are discussed in Section 5.3.

5.2.3 Other Exploration Methods

No other methods of exploration (such as airborne or ground geophysical surveys) are reported for the Piranha and Taylor properties.

5.3 Laboratory Testing Results

The relatively uniform nature of the Wonewoc sand formation underlying the Piranha and Taylor properties, combined with laboratory test results, indicated that the Piranha and Taylor properties are capable of producing a suite of 20/140-mesh frac sand products that meet customer specifications for frac sand use.

5.3.1 Grain Size Distribution

Grain size distribution was analyzed according to API RP 19C/ISO 13503-2, Section 6.

5.3.1.1 Piranha

A table of weighted average grain size distribution of the dry plant feed, based on laboratory testing results, is shown in Table 5.1.

Table 5.1: Weighted Average Particle Size Distribution

Approximate Grain Size Distribution of Dry Plant Feed (%)		
20/40	40/70	70/140
30.2	53.8	16.0

The preceding table highlights the relative size mix of the sand found within the Piranha Property, indicating approximately 70% of the sand particles are concentrated in the 40/140-mesh sand faction.

5.3.1.2 Taylor

A table of weighted average grain size distribution of the dry plant feed, based on laboratory testing results, is shown in Table 5.2.

Table 5.2: Weighted Average Particle Size Distribution

Approximate Grain Size Distribution of Dry Plant Feed (%)			
20/40	30/50*	40/70	70/140
25.2	43.4	48.6	26.2

* Note that 30/50 size produced may only be made in lieu of an equivalent portion of 20/40 and 40/70 size material, as these product sizes overlap and are not cumulative.

The preceding table highlights the relative size mix of the sand found within the Taylor Property, indicating approximately 75% of the sand particles are concentrated in the 40/140-mesh sand faction.

5.3.2 Grain Shape (Sphericity and Roundness)

Grain shape was analyzed according to ISO 13503-2/API RP19C, Section 7. Under this standard, recommended sphericity and roundness values for proppants are 0.6 or greater. As part of the grain shape analysis, the presence of grain clusters (weakly cemented grain aggregates) and their approximate proportion in the sample were reported.

5.3.3 Crush Resistance

Crush resistance is a key test that determines the amount of pressure a sand grain can withstand under laboratory conditions for a two-minute duration. The sample was analyzed according to ISO 13503-2/API RP19C, Section 11. Under this standard, the

highest stress level (psi) in which the proppant produces no more than 10% crushed fine material is rounded down to the nearest 1,000 psi and reported as the "K-value" of the material.

5.3.4 Acid Solubility

Acid solubility was analyzed according to ISO 13503-2/API RP19C, Section 8. Under this standard, 5 grams of sand is treated with 100 milliliters of 12:3 hydrochloric acid to hydrofluoric acid at 150°F for 30 minutes. The recommended maximum acid solubility for proppants in the 6/12 through 30/50-mesh size range is 2.0%, and for proppants in the 40/70-mesh and finer size range is 3.0%.

5.3.5 Turbidity

Turbidity was analyzed according to ISO 13503-2/API RP19C, Section 9. Under this standard, the suggested maximum frac sand turbidity should be equal to or less than 250 nephelometric turbidity units (NTU).

5.3.6 Quality Summary

5.3.6.1. Piranha

API/ISO frac sand characterization is supported by samples composited from seven drill holes spaced across the property. Testing was conducted by PropTester, Inc. laboratories located in Cypress, Texas according to the procedures outlined in ISO 13503-2/API RP19C, Section 11 and API RP 56/58/6. Testing was completed on four anticipated product sizes: 20/40, 30/50, 40/70, and 70/140 (100-mesh). Each product size had a full suite of API RP 19C testing performed in order to assess the proppant characteristics relative to standard industry specification. Results of the API testing are in Table 5.3 below.

Table 5.3: Piranha API/ISO Test Results

	20/40-Mesh		30/50-Mesh		40/70-Mesh		100-Mesh	
Test	Result	Limit	Result	Limit	Result	Limit	Result	Limit
Roundness	0.8	0.6 ≥	0.7	0.6 ≥	0.7	0.6 ≥	0.7	0.6 ≥
Sphericity	0.8	0.6 ≥	0.8	0.6 ≥	0.8	0.6 ≥	0.8	0.6 ≥
Turbidity (NTU)	5	≤ 250	6	≤ 250	6	≤ 250	15	≤ 250
Acid Solubility (%)	1.5	≤ 2.0	1	≤ 2.0	0.9	≤ 3.0	5	≤ 3.0
K-Value (psi)	6K	-	7K	-	8K	-	8K	-

API/ISO product test results indicate an overall premium NWS proppant material that is typically produced from the Wonewoc Formation. Quality characteristics tend to exceed API recommended minimum specifications. BOYD notes that the Piranha operation has been selling various frac sand sized products their customers.

5.3.6.2. Taylor

A composite sample split obtained from Taylor's first drilling and sampling program and historic site laboratory data were utilized to demonstrate the quality of the 20/40-mesh, 30/50-mesh, and 40/70-mesh product sizes. Because of the first drilling program's focus on the coarse sand material, 20/70-mesh material, API RP 19C testing was not performed on the 70/140-mesh material. The test results from the suite of 20/70-mesh products are presented in Table 5.4 below.

Table 5.4: Taylor API/ISO Test Results

	20/40-Mesh		30/50-Mesh		40/70-Mesh	
Test	Result	Limit	Result	Limit	Result	Limit
Roundness	0.7	0.6 ≥	0.6	0.6 ≥	0.7	0.6 ≥
Sphericity	0.8	0.6 ≥	0.8	0.6 ≥	0.8	0.6 ≥
Turbidity (NTU)	33	≤ 250	41	≤ 250	55	≤ 250
Acid Solubility (%)	0.6	≤ 2.0	0.8	≤ 2.0	1	≤ 3.0
K-Value (psi)	6K	-	7K	-	9K	-

API/ISO product test results indicate an overall premium NWS proppant material that is typically produced from the Wonewoc Formation. Quality characteristics tend to meet or exceed API recommended minimum specifications. BOYD notes that the Taylor operation has been selling various frac sand sized products to their customers.

5.4 Data Verification

BOYD prepared the resource/reserve reports for the Piranha Property and the Taylor Property and associated updates to the estimated resources and reserves tons through December 31, 2020, for the subject properties.

The December 31, 2021, frac sand reserve estimates for the Piranha Property and the Taylor Property are based on historic drill hole data previously reviewed and utilized by BOYD in the preparation of our prior frac sand resource and reserve estimates. As we have previously judged the exploration drilling and sampling data representative and reasonable, we opine that they are still representative and reasonable for use in the December 31, 2021, frac sand resource and reserve estimates for the subject properties.

6.0 FRAC SAND RESOURCES AND RESERVES

6.1 Applicable Standards and Definitions

Unless otherwise stated, frac sand resource and frac sand reserve estimates disclosed herein are completed in accordance with the standards and definitions provided by S-K 1300. It should be noted that BOYD considers the terms "mineral" and "frac sand" to be generally interchangeable within the relevant sections of S-K 1300.

Estimates of any mineral resources and reserves are always subject to a degree of uncertainty. The level of confidence that can be applied to a particular estimate is a function of, among other things: the amount, quality, and completeness of exploration data; the geological complexity of the deposit; and economic, legal, social, and environmental factors associated with mining the resource/reserve. By assignment, BOYD used the definitions provided in S-K 1300 to describe the degree of uncertainty associated with the estimates reported herein.

The definition of mineral (frac sand) resource provided by S-K 1300 is:

> *Mineral resource is a concentration or occurrence of material of economic interest in or on the Earth's crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity, that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.*

Estimates of frac sand resources are subdivided to reflect different levels of geological confidence into measured (highest geologic assurance), indicated, and inferred (lowest geologic assurance)

The definition of mineral (frac sand) reserve provided by S-K 1300 is:

> *Mineral reserve is an estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it 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.*

Estimates of frac sand reserves are subdivided to reflect geologic confidence, and potential uncertainties in the modifying factors, into proven (highest assurance) and probable.

Figure 6.1 shows the relationship between mineral (frac sand) resources and mineral (frac sand) reserves.

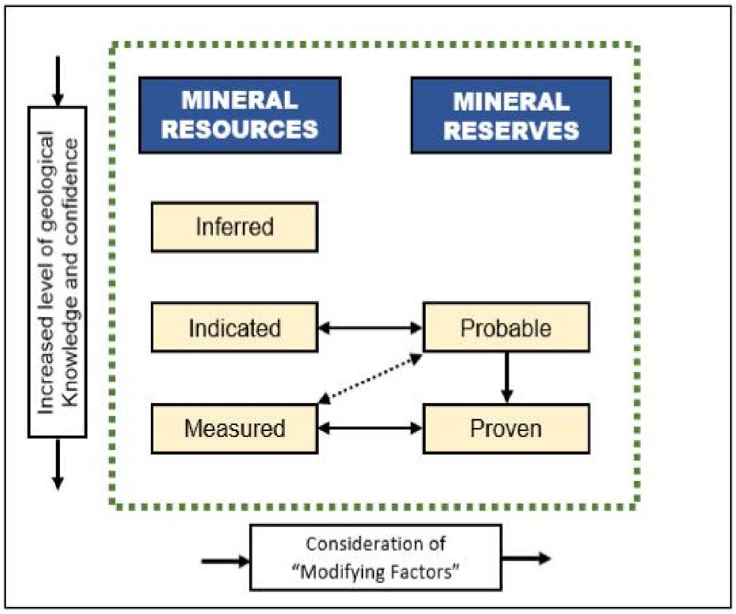

Figure 6.1: Relationship Between Frac Sand Resources and Frac Sand Reserves

In this report, the term "frac sand reserves" represent the tonnage of frac sand products that meets customer specifications and will be available for sale after processing of the ROM sand.

6.2 Frac Sand Resources

6.2.1 Methodology

6.2.1.1 Piranha

BOYD independently prepared estimates of in-place frac sand for the Piranha Property. In 2017, BOYD prepared a geologic model of the sand deposits within the Piranha Property as of March 31, 2017, and in April 2018 we revised the resource data to include the Conoboy property, which was purchased in January 2018.

In preparing our estimates of in-place frac sand for the Piranha Property, BOYD notes the following:

1. BOYD compiled a database containing overburden thickness, sand depth, sand thickness, and other information on a by drill hole basis from the various drilling and sampling programs performed. The geologic data contained in the database was imported into Carlson Software (Carlson), a geologic modeling and mine planning software suite that is widely used and accepted by the mining industry throughout the United States.
2. A geologic model of the deposit was created in Carlson using industry-standard grid modeling methods well-suited for simple stratigraphic deposits, and for estimating overburden and sand volumes and associated product distribution. The geologic model delineates overburden, the top and bottom of the mineable sand horizon and the distribution of the product size fractions across the deposit.
3. Mineable sand is present over most of the subject property, except for certain areas where drilling noted the presence of glacial till material where part or all of the Wonewoc sand unit is eroded. The till areas appear to be isolated and somewhat well-defined due to the combination of past exploration drilling and the extent of current and past mining activities on the property. Adjustments were made in the model to account for the anomalous areas, property mining offsets, and removing areas already mined.
    a. In 2017, the Conoboy property was targeted as a potential acquisition. It was independently analyzed but not included in the 2017 resource numbers. Later in 2018, the model data was updated to include the effect of adding the Conoboy property to the resource estimates.
4. In-place volumes for each of the proposed mining blocks were calculated from the Carlson geologic model. An in-place sandstone dry density of 130 pounds per cubic foot was used to convert the in-place sand volumes to in-place short tons.
5. BOYD utilized post March 31, 2017, production data provided by Mammoth, in conjunction with the Conoboy data, to reconcile the estimate from the March 31, 2017, volumetric estimate to December 31, 2021.

6.2.1.2 Taylor

BOYD independently prepared estimates of in-place frac sand for the Taylor Property. In February 2018, BOYD prepared a geologic model of the sand deposits within the Taylor Property as of December 31, 2017. The geologic model was revised in January 2019 due to:

1. A change to property boundary setback requirements resulting from a variance approval from the Jackson County Zoning and Sanitation Administration in November 2018.

2. The availability of additional sieve data related to the rotary holes drilled in the February 2018 drilling and sampling program (Chapter 5) that were not included in the geologic model used to calculate the resource tons reported in the February 2018 report.

In preparing our estimates of in-place frac sand for the Taylor Property, BOYD notes the following:

1. All available drill hole records, the compiled grain size distribution data for each analyzed interval obtained from the Bay report and from the February 2018 drilling and sampling program, as well as the API results provided to BOYD, were compiled into a database for use in modeling the quantity of mineable sand underlying the Taylor Property. BOYD also used historical experience at Taylor and our knowledge of other Wonewoc Formation operations, to assign product size distribution.
2. BOYD obtained an updated topographic contour map, produced by Mau & Associates, Green Bay, Wisconsin, of the active pit area that was produced from a drone recording LIDAR measurement within the active portion of the mine property in May 2017. The May 2017 map was adjusted by BOYD based on information obtained during our site visit in January 2018 to reasonably reflect the mining boundaries as of December 31, 2017.
3. The mineable area was initially defined by applying a 50-ft offset inside of the entire property line. Areas around the wet and dry plants, access roads, and mine office buildings were also excluded from the estimate, with 50-ft offsets placed around these areas. A final vertical pit slope was utilized from the surface to the bottom of the defined mineable sand interval. In November 2018, Taylor provided an updated variance map showing that all common property boundaries between Taylor Frac and Badger Mining may now be reduced to allow mining within 40 ft of these property lines, versus the initially required 100-ft property line offset. All other property line offsets remained at 100-ft offsets. This change was incorporated into the geologic model.
4. The mineable sand interval was defined using drill hole sand thickness data and topographic mapping provided by Bay and the 2018 drilling program. This information was also utilized to identify the overburden thickness. Carlson's geological modeling software was used to calculate the resource volume and overburden volume. An in-place sandstone dry density of 118.5 pounds per cubic foot was used to convert the in-place sand volumes to in-place short tons.
5. BOYD utilized post December 31, 2017, production data provided by Mammoth, along with the BOYD January 2019 Report amending the resource tons as of December 31, 2017, to reconcile the estimate from the December 31, 2017, volumetric estimate to December 31, 2021.

6.2.2 Classification

Geologic assuredness is established by the availability of both structural (thickness and elevation) and quality (size fraction) information for the deposit. Resource classification is generally based on the concentration or spacing of exploration data which can be used to demonstrate the geologic continuity of the deposit. When material variations in thickness, depth, and/or sand quality occur between drill holes, the allowable spacing distance between drill holes is reduced.

6.2.2.1 Piranha

The Qualified Person has determined the area under study related to the Piranha Property are well explored and exhibit acceptable drill hole data spacing to be classified as a measured resource.

In addition, we note that the deposit is technically and legally mineable, as evidenced by previous operation and the available documentation provided. It is BOYD's understanding that there are no outstanding legal or regulatory issues regarding this property.

BOYD is of the opinion that there is a low degree of uncertainty associated with the Piranha resource classification.

6.2.2.2 Taylor

The Qualified Person has determined the area under study related to the Taylor Property have acceptable sample spacing to classify as a Measured Resource as determined by a qualified person having the requisite experience with mining in the Wonewoc Formation.

In addition, we note that the deposit is technically and legally mineable as evidenced by the documentation provided for this mining operation. It is BOYD's understanding that there are no outstanding legal or regulatory issues regarding this property.

BOYD is of the opinion that there is a low degree of uncertainty associated with the Taylor resource classification.

6.2.3 Frac Sand Resource Estimate

There are no reportable frac sand resources excluding those converted to frac sand reserves for the Piranha Mine and the Taylor Mine. Quantities of frac sand controlled by Mammoth within the defined boundaries of the Piranha Property and the Taylor

Property, which are not reported as frac sand reserves are not considered to have potential economic viability; as such, they are not reportable as frac sand resources.

6.2.4 Validation

BOYD independently estimated in-place frac sand resources for the Piranha Mine and the Taylor Mine based on the provided drilling, sampling, and testing data obtained from Mammoth. Utilizing industry-standard grid modeling techniques we have estimated volumes of frac sand indicated by such data. Based on our review of the information provided by Mammoth, we are of the opinion that the data provided are reasonable and appropriate.

Furthermore, it is our opinion that the estimation methods employed are both appropriate and reasonable for the deposit type and proposed extraction methods.

6.3 Frac Sand Reserves

6.3.1 Methodology

6.3.1.1 Piranha

Estimates of frac sand reserves for the Piranha Mine were derived contemporaneously with estimates of frac sand resources. To derive an estimate of saleable product tons (proven and probable frac sand reserves), the following modifying factors were applied to the in-place measured and indicated frac sand resources underlying the respective mine plan areas:

- A 90% mining recovery factor, which assumes that 10% of the mineable (in-place) frac sand resource will not be recovered during mining for various reasons. Applying this recovery factor to the in-place resource results in the estimated ROM sand tonnage that will be delivered to the wet process plant.

- An overall 79% processing recovery. This recovery factor accounts for losses in the wet and dry plants. This recovery factor accounts for removal of out-sized (i.e., larger than 20-mesh and smaller than 140-mesh) sand and losses in the wet and dry processing plants due to minor inefficiencies.

The overall product yield (after mining and processing losses) for the Piranha Mine is estimated at approximately 71%. That is, for every 100 tons of in-place frac sand resources mined, approximately 71 tons will be recovered and sold as product.

BOYD utilized post March 31, 2017, production data provided by Mammoth, in conjunction with the Conoboy data, to reconcile the estimate from the March 31, 2017, volumetric estimate to December 31, 2021.

As previously noted, there are no reportable frac sand resources. However, Table 6.1 provides insight into the frac sand in-place resources tons that would be eventually mined and converted into frac sand product tons for the Piranha Mine. The frac sand product tons are equivalent to the total frac sand reserve tons as of December 31, 2021, for the Piranha Mine.

Table 6.1: Mineable and Reserve Tons as of December 31, 2021

Piranha Property In-Place, ROM and Product Tons			
Tons (000)	In-Place	ROM*	Product**
Measured	53,391	48,052	37,814

*Run-of-Mine tons calculated using a 90% mining recovery.
**Product tons calculated using 79% processing recoveries.

6.3.1.2 Taylor

Estimates of frac sand reserves for the Taylor Mine were derived contemporaneously with estimates of frac sand resources. To derive an estimate of saleable product tons (proven and probable frac sand reserves), the following modifying factors were applied to the in-place measured and indicated frac sand resources underlying the respective mine plan areas:

- A 90% mining recovery factor, which assumes that 10% of the mineable (in-place) frac sand resource will not be recovered for various reasons. Applying this recovery factor to the in-place resource results in the estimated ROM sand tonnage that will be delivered to the wet process plant.

- An overall 73% processing recovery. This recovery factor accounts for losses in the wet and dry plants. This recovery factor accounts for removal of out-sized (i.e., larger than 20-mesh and smaller than 140-mesh) sand and losses in the wet and dry processing plants due to minor inefficiencies.

The overall product yield (after mining and processing losses) for the Taylor Mine is estimated at approximately 66%. That is, for every 100 tons of in-place frac sand resources mined, approximately 66 tons will be recovered and sold as product.

BOYD utilized post December 31, 2017, production data provided by Mammoth, along with the BOYD January 2019 Report (amending the resource tons as of December 31,

2017) to reconcile the amended estimate from the December 31, 2017, to the December 31, 2021, estimate.

As previously noted, there are no reportable frac sand resources. However, Table 6.2 provides insight into the frac sand in-place resources tons that would be eventually mined and converted into frac sand product tons for the Taylor Mine. The frac sand product tons are equivalent to the total frac sand reserves as of December 31, 2021, for the Taylor Mine.

Table 6.2: Mineable and Reserve Tons as of December 31, 2021

Taylor Property In-Place, ROM and Product Tons			
Tons (000)	In-Place	ROM*	Product**
Measured	36,951	33,256	24,277

*Run-of-Mine tons calculated using a 90% mining recovery.
**Product tons calculated using 73% processing recoveries.

6.3.2 Classification

Proven and probable frac sand reserves are derived from measured and indicated frac sand resources, respectively, in accordance with S-K 1300. BOYD is satisfied that the frac sand reserve classification reflects the outcome of technical and economic studies.

6.3.3 Frac Sand Reserve Estimate

6.3.3.1 Piranha

Mammoth's estimated surface mineable frac sand reserves for the Piranha Property total approximately 37.8 million saleable product tons, as of December 31, 2021. Figure 6.2 provides an overview of the sand reserves located on the property.

The Table 6.3 presents the estimated Reserve tons by product (size) owned in fee, which are anticipated to be produced at Mammoth's Piranha Property.

Table 6.3: Piranha Reserves as of December 31, 2021

Estimated Reserve Tons By Classification as of December 31, 2021			
Proven Tons (000)			
20/40-Mesh	40/70-Mesh	70/140-Mesh	Total
11,414	20,333	6,067	37,814

Q:\CAD_GROUP\3756.007\FIGURE 6_2.DWG

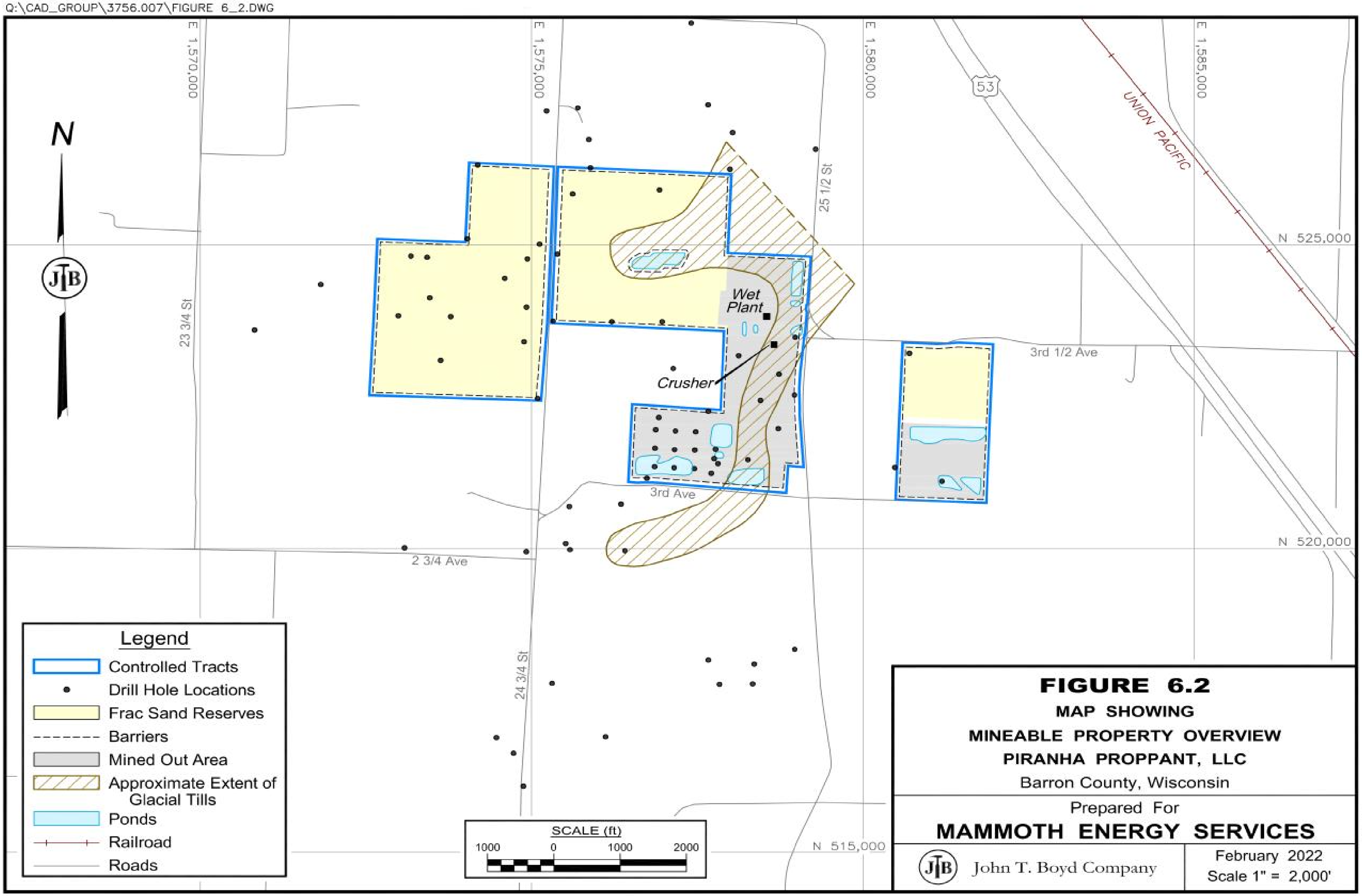

FIGURE 6.2
MAP SHOWING
MINEABLE PROPERTY OVERVIEW
PIRANHA PROPPANT, LLC
Barron County, Wisconsin

Prepared For
MAMMOTH ENERGY SERVICES

John T. Boyd Company

February 2022
Scale 1" = 2,000'

Of the total frac sand reserves for the Piranha Mine as of December 31, 2021, it is our conclusion that approximately 100% of the stated reserves can be classified on the proven reliability category (the highest level of assurance).

6.3.3.2 Taylor

Mammoth's estimated surface mineable frac sand reserves for the Taylor Property total approximately 24.3 million saleable product tons, as of December 31, 2021. Figure 6.3 provides an overview of the sand reserves located on the property.

The Table 6.4 presents the estimated Reserve tons by product (size) owned in fee, which are anticipated to be produced at Mammoth's Taylor Property.

Table 6.4: Taylor Reserves as of December 31, 2021

Estimated Reserve Tons By Classification as of December 31, 2021			
Proven Tons (000)			
20/40-Mesh	40/70-Mesh	70/140-Mesh	Total
6,109	11,801	6,367	24,277

Of the total frac sand reserves for the Taylor Mine as of December 31, 2021, it is our conclusion that approximately 100% of the stated reserves can be classified on the proven reliability category (the highest level of assurance).

6.3.3.3 General

The estimated product distribution of the frac sand reserves is based on available laboratory gradation test data provided by Mammoth. Grain size distribution and overall yields may vary based on the depth and location at which mining occurs.

The Piranha and Taylor properties, and other frac sand operations in the area, have a well-established history of mining and selling frac sand products into the various energy basin fields. BOYD has assessed that sufficient studies have been undertaken to enable the frac sand resources to be converted to frac sand reserves based on current and proposed operating methods and practices. Changes in the factors and assumptions employed in these studies may materially affect the frac sand reserve estimate.

The extent to which the frac sand reserves may be affected by any known geological, operational, environmental, permitting, legal, title, variation, socio-economic, marketing, political, or other relevant issues has been reviewed as warranted. It is the opinion of BOYD that Mammoth has appropriately mitigated, or has the operational acumen to mitigate, the risks associated with these factors. BOYD is not aware of any additional risks that could materially affect the development of the frac sand reserves.

Q:\CAD_GROUP-jfg\3756.007\FIGURE 6_3.DWG

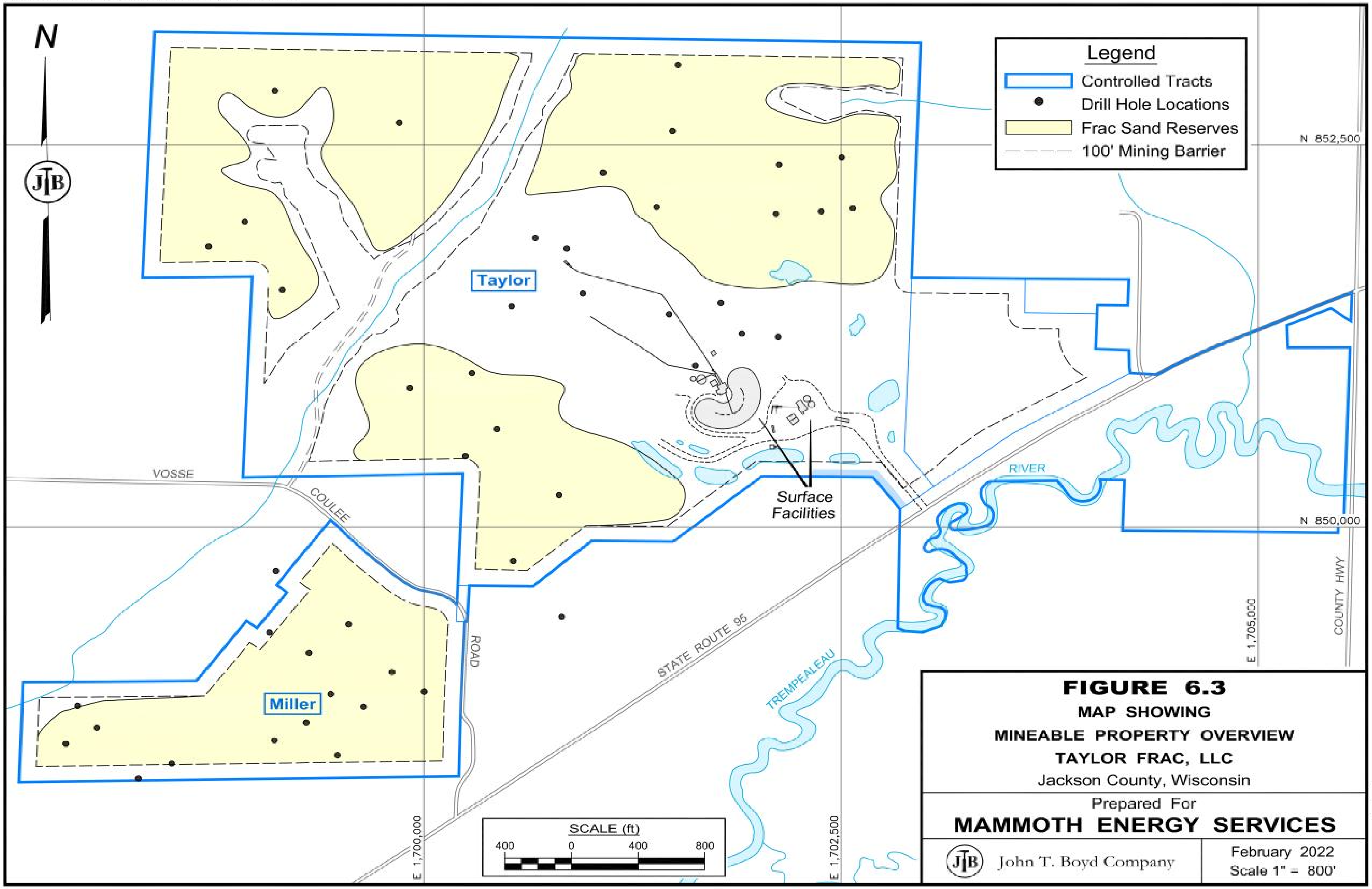

FIGURE 6.3
MAP SHOWING
MINEABLE PROPERTY OVERVIEW
TAYLOR FRAC, LLC
Jackson County, Wisconsin

Prepared For
MAMMOTH ENERGY SERVICES

John T. Boyd Company | February 2022 | Scale 1" = 800'

Based on our independent estimate and operations review, we have a high degree of confidence that the estimates shown in this report accurately represent the available frac sand reserves controlled by Mammoth, as of December 31, 2021.

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7.0 MINING AND PROCESSING OPERATIONS

7.1 Mining and Processing Methods

The Piranha and Taylor mines excavate sand from the Wonewoc Formation using medium-sized earthmoving equipment and conventional surface mining techniques Figure 7.1. shows a typical mining face at one of the operations. Processing operations located on the individual properties then wash, dry, and sort/size the excavated sand to yield products that are of sufficient quality for hydraulic fracturing (i.e., frac sand).

Figure 7.1: Typical Wonewoc Sand Formation Face Area at Piranha and Taylor

7.1.1 Taylor Mine and Operation

The Taylor operation includes the mining, wet process, and dry process plants located near the town of Taylor in west-central Jackson County, and the rail loadout facility located approximately 2.3 miles southwest of the mining operation on State Route 95 in

Trempealeau County. Figure 7.2 illustrates the general site layout of the mine and process plants. The off-site rail loadout is not shown.

Figure 7.2: General Overview of Taylor Mine Pit and Process Plants

The mining operation is conducted in a sequential series of steps or tasks. The initial step involves the clearing and grubbing of vegetation, followed by removal of overburden (i.e., dirt and rock) to expose the top of the sandstone. Initially, the overburden material will be excavated by mechanical equipment until such a time as the rock becomes competent (hard) and drilling and blasting of the material is necessary. The target friable Wonewoc sandstone material is then drilled and blasted in successive benches. The ROM sand material is loaded with front-end loaders into an in-pit crusher/feeder system that conveys the material to a surge hopper prior to being fed into the wet process plant. The drilling and blasting of the sand is contracted to a third-party company. Approximately 350 tph of ROM material will be delivered to the wet plant for processing.

In the wet process plant, the plus 20-mesh oversize will be removed by wet screens and the minus 140-mesh fine waste material will be segregated (and removed) using hydrosizers and cyclones. The plant utilizes attrition scrubbers to ensure a low turbidity

product free of clusters. The waste stream of fines from the wet plant is directed to a thickener with the thicken sludge removed and the resultant overflow water routed to ponds for process water recycling. Output from the wet plant is estimated at 250 tph of feedstock material containing 13% to 15% moisture.

The wet plant product consists of a minus 40-mesh to a plus 140-mesh material that is stockpiled. A front-end loader feeds the processed sand into the dry process plant for drying and finished screening. The dry processing plant consists of two Stark Aire fluid bed dryers: a 100 tph and a 150 tph. Gas to fuel the dryers is supplied via a direct pipeline. The dried product is fed onto eight sets of four-deck Rotex screens. The waste product from the baghouses is conveyed back to the mine site area for disposal and/or use in reclamation.

Finished product from the dry plant is stored in 1 of 10 product silos having a combined 18,400 tons of capacity. The final product is weighed then trucked from the product storage silos to the Taylor off-site rail loadout facility. The rail loadout is serviced by the Canadian National Railway. A full suite of dried frac sand products are produced: 20/40-mesh, 30/50-mesh, 40/70-mesh, and 70/140-mesh (100-mesh). The overall nameplate capacity for the operation is approximately 1.8 million tons per year of saleable product.

7.1.2 Piranha Mine and Operation

Figure 7.3: General Overview of Piranha Mine Pit, Process Plants, and Rail Loadout

The Piranha mining operation is similar to the Taylor operation as the same formation of sandstone is being mined. After the target sandstone bench is cleared of overburden, it is drilled and blasted by a third-party contractor. The mining is also performed by a third-party contractor. The ROM sand is loaded into a 40-ton articulated truck and hauled to the primary crusher stockpile. ROM sand material is then fed into the primary crusher and scalping screen with a front-end loader. The oversize is crushed then screened and stockpiled onto a reclaim tunnel system. The sand is fed onto a tunnel reclaim belt that conveys the material to the wet process plant. Here, the sand is classified into a 40/140-mesh material. A series of wet screens, hydrosizers, and cyclones are used to classify the material. The fines waste material is routed to a thickener and belt presses to reclaim process water. The majority of the process water is recycled from the on-site process water ponds. Makeup water is sourced from on-site water wells. The filter cake sludge material is hauled to reclamation areas and mixed with spoil to be used to reclaim the property.

The resultant wet plant stockpile material is trucked approximately 1.5 miles by third-party trucks to the dry process/rail loadout site east of the mine. The material is stockpiled and fed by loader into one of two dry process plants as needed. The material is dried by natural gas fired dryers and screened on multi-deck Rotex screens. Both plants utilize a Carrier 150 tph fluid bed dryer for a combined throughput of 300 tph. The nameplate capacity of the plant is approximately 2.0 million tons per year of finished product. Finished products are stored in one of six product storage silos that have a combined storage capacity of 18,000 tons. The silos directly load material into railcars. The predominant products produced at the site are 20/40-mesh, 30/50-mesh, and 40/70-mesh frac sand. Piranha has a circular unit train loadout system. The rail loadout has direct access to the UP Railway via the Progressive short line Railroad.

7.2 Schedule, Equipment, and Staffing

Both mine sites operate 24 hours per day, Monday through Thursday of each week during the season. The mine and wet process plant generally operate April/May through October/November of each year. The working hours are variable as they are based on product demand.

The dry process plants at each site operate continuously if product demand warrants. Scheduled/unscheduled downtime and maintenance are the only exceptions to the schedule. The rail loadout operates continuously or as demand warrants.

The hourly workforce at Taylor consists of 18 personnel performing all but the drilling and blasting functions. The Piranha operation employs 22 hourly workers who perform all but the drilling, blasting, and mining activities. There is one salary position at Taylor and two salary positions at Piranha. An additional salary position is split between the two operations.

7.3 Historical and Forecast Production

7.3.1 Historical Mine Production and Process Yield

Mammoth produces predominantly 20/40-mesh,30/50-mesh, and 40/70-mesh frac sand products, as well as a 70/140-mesh product that are railed to their final destination in the energy basins.

The sand is mined, processed, stored, and shipped from both of the facilities by rail.

Historic frac sand production from the operations are as follows:

Table 7.1: Historic Frac Sand Production

Year	Taylor ROM Tons (000)	Piranha ROM Tons (000)
2019	1,649	2,099
2020*	589	0
2021	567	320

*Covid Period included.

The ROM production from the mining pit is converted into saleable product after processing. The process yield estimates the percentage of ROM sand that becomes finished product following the removal of waste and other inefficiencies. The Taylor operation has an estimated process yield of approximately 73% and the Piranha operation has an estimated process yield of approximately 79%

7.3.2 Forecasted Production

Forecasted ROM sand production is estimated as follows:

Table 7.2: Forecasted ROM Production Tons

ROM tons (000):	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Taylor	875	875	875	875	875
Piranha	853	853	853	853	853

7.4 Mine Plan (Life-of-Mine)

7.4.1 Piranha Mine

The Piranha long-term mine plan is illustrated in Figure 7.4. Each numbered perimeter represents approximately two years of ROM production. This plan will change as sales demand varies, sometimes significantly, from year to year. The plan represents mining a significant amount of the total estimated reserves but is not intended to match the total reserve estimate.

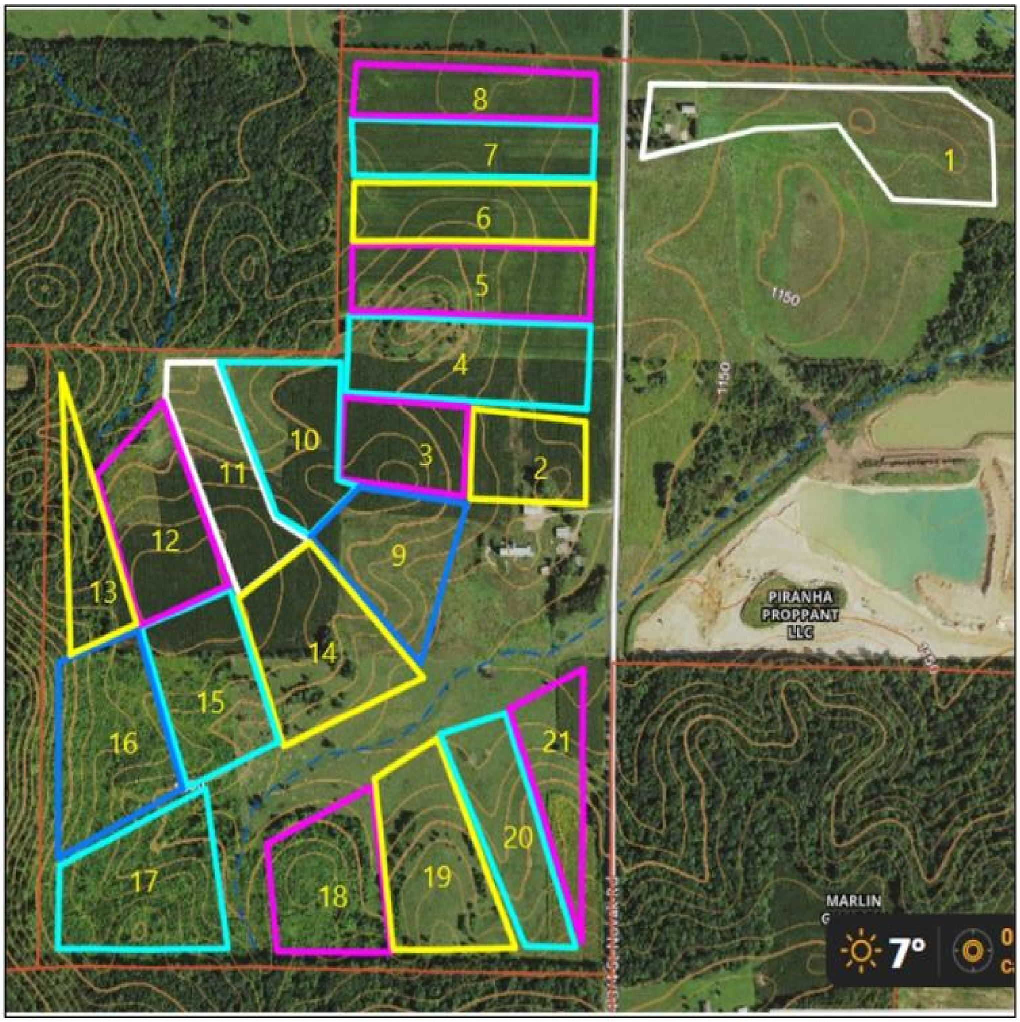

Figure 7.4: Piranha Long-Term Mine Plan

The mining area or pit will recover the northern section of the eastern property shown in the next two years before moving directly westward (2) of the current mining area. The approximate advance of mining is shown for the next 42 years.

7.4.2 Taylor Mine

The Taylor long-term mine plan is illustrated in Figure 7.5. Each numbered perimeter represents approximately two years of ROM production. This plan will change as sales demand varies, sometimes significantly, from year to year. The plan represents mining a

significant amount of the total estimated reserves but is not intended to match the total reserve estimate.

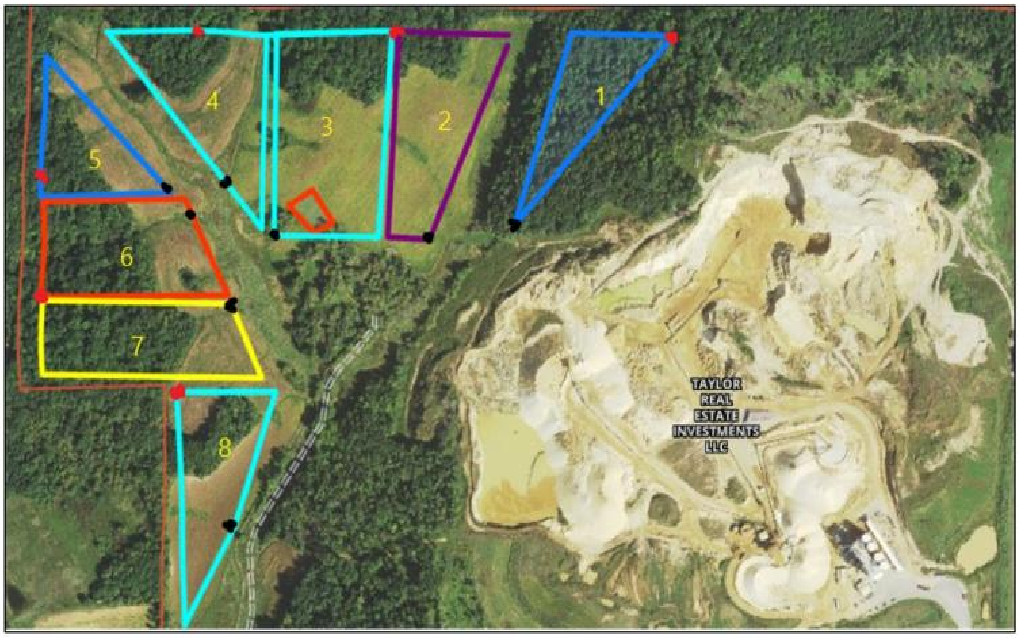

Figure 7.5: Taylor Long-Term Mine Plan

The mining area or pit will advance westward over the next eight years before turning southward. The approximate advance of mining is shown for the next 16 years.

7.4.3 Operational Risks

Surface mines face two primary types of operational risks. The first category of risk includes those daily variations in physical mining conditions, mechanical failures, and operational activities that can temporarily disrupt production activities. Several examples are as follows:

- Process water spot shortages.
- Power curtailments.
- Variations in grain size consistency.
- Encountering excessive clay and other waste material.
- Failures or breakdowns of operating equipment and supporting infrastructure.
- Adverse weather disruptions (power outages, dust storms, excessive heat etc.).

The above conditions/circumstances can adversely affect production on any given day, but are not regarded as "risk issues" relative to the long-term operation of a mining entity. Instead, these are considered "nuisance items" that, while undesirable, are encountered on a periodic basis at many mining operations. BOYD does not regard the issues listed above as being material to both mining operations or otherwise compromising its forecasted performance.

The second type of risk is categorized as "event risk." Items in this category are rare, but significant occurrences that are confined to an individual mine, and ultimately have a pronounced impact on production activities and corresponding financial outcomes. Examples of event risks are major fires or extreme droughts, floods, or unforeseen geological anomalies that disrupt extensive areas of proposed or operating mine workings and require alterations of mining plans. Such an event can result in the cessation of production activities for an undefined but extended period (measured in months, and perhaps years) and/or result in the sterilization of frac sand reserves. This type of risk is minimal in a relatively basic surface sand mining operation.

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8.0 INFRASTRUCTURE

On-site facilities at each site include a scale house, office, shop, and a quality laboratory. The surface facilities currently located at the mine are well constructed and have the necessary capacity/capabilities to support both of the operations. Operational preference may constitute the upgrading of some existing facilities if the operation expands in the future.

The Taylor Plant is serviced by Xcel Electric,LLC and the Piranha Plant is serviced by Barron Electric Company.

Natural gas to both operations is supplied by line natural gas by Constellation Gas Company.

Plant process water is recycled within both plants and is pumped from freshwater process ponds on-site to the wash plants. Additional makeup water is obtained from on-site water wells if needed.

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9.0 MARKET ANALYSIS

The frac sand market appears to be set for recovery in 2022. After several years of depressed pricing and volume, activity in all basins show signs of a meaningful uptick. In Western Canada the expectation is an increase of 20%-35% in total volume, much of that focused on the first quarter of 2022. In tandem West Texas has already reached a fever pitch with reports of many companies not getting their sand needs met, and reports of price increases as high as 20%. This has led to conversations around bringing NWS volumes back to the Permian basin for the first time in several years.

On pricing, recently US Silica (a competitor of Mammoth) announced a pricing increase on sand sold up to 10% in January 2021. Anecdotally, prices of $20-$30 per ton for 40/70 spot sand have started to receive traction for volumes shipped on the railroad in Wisconsin. Furthermore, the demand for ancillary grades, such as 20/40 and 30/50, have started to tick up. This is resulting in elevated pricing on all grades, not just 40/70.

One mitigating factor impacting overall availability is the current labor shortage in the United States. Many plants are reporting difficulty bringing on new talent which is causing many plants to fall short of their volume potential.

Specifically concerning the Taylor and Piranha plants, Taylor ships sand through their CN rail loadout and Piranha ships sand though their UP loadout. The ability to ship on both of these mainline railways essentially allows Mammoth to participate in all of the energy basins., We cannot practically review all of the basins in order to provide examples of in-basin activity. For this reason, we have chosen to review the Permian, by far the bellwether for the entire North American unconventional energy industry and a large customer of the Piranha operation. Additionally, the Appalachian Basin and Niobrara Basins, are smaller, but indicate activity for the CN railway or customers of the Taylor operation. Generally, activity in the Permian is often a leading indicator of trends in all of the North American Basins including Canada.

9.1 Permian Basin

Permit submissions for horizontal oil and gas wells in the Permian Basin indicate a continuation of strong drilling ahead. Utilizing data from Baker Hughes and the RRC of TX, the total number of permits filed per average annual working rig for 2021 is tracking at multi-year highs as evidenced in the chart below. For calendar year 2021, there was a

total of 4,413 permit submissions with an average 227 horizontal rigs active in the Permian Basin (ratio of 19.5).

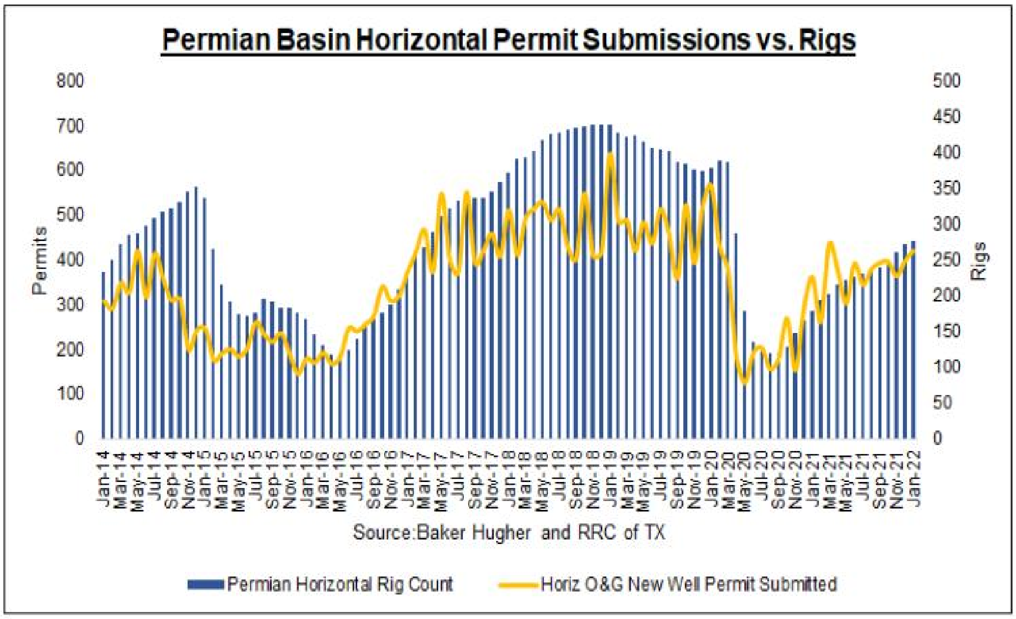

Figure 9.1: Permian Basin HZ Permit Submissions vs. Rigs

Rig counts in the Permian Basin are up approximately 64% as of year-end 2021 versus 2020. This has led to increased production for both crude oil and natural gas. Over the same time-period, crude oil production (barrels per day) and natural gas production (thousand cubic feet per day) in the Permian Basin are up 13% and 16%, respectively. Both Permian Basin daily crude oil production and daily natural gas production continue to exceed pre-pandemic peaks and reach new records. As of year-end 2021, crude oil production in the basin is nearly 5.0 million barrels per day while basin natural gas production stands at 19.8 billion cubic feet per day.

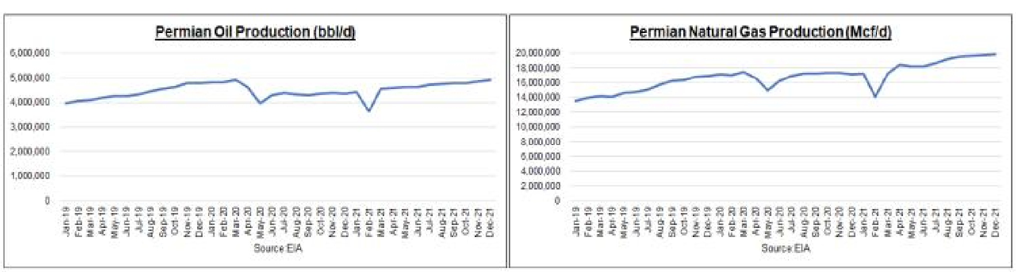

Figure 9.2: Permian Oil Production and Natural Gas Production

Consequently, with increases in production and well completions, activity at frac sand mines in the region have increased. According to MSHA, operating hours for the third quarter of 2021 for Permian Basin frac sand mines were up 36% since year-end 2020.

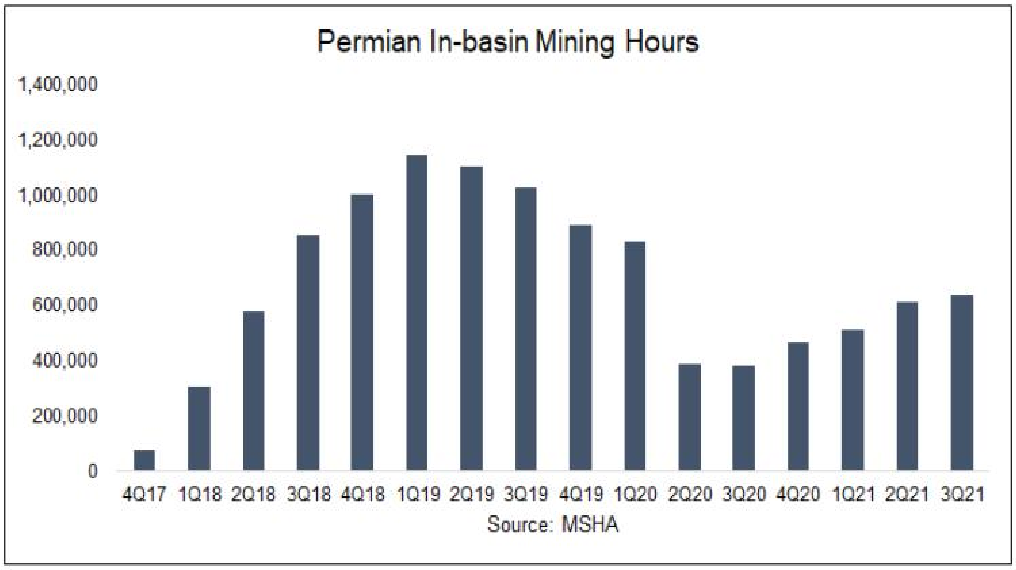

Figure 9.3: Permian Wide In-Basin Mine Operating Hours (Quarterly)

According to industry reports, all but one frac sand mine in the Permian Basin is currently fully operational. However, total in-basin mine operating hours are still about 45% below their historical peak. Generally, mine operating hours correlate well with crude oil and natural gas production and drilling and uncompleted (DUC) well data. Current frac sand production in the Permian Basin is estimated to be nearing prior peak production of about 70 million tons leading to stable pricing in the basin. This supply and demand analysis for in-basin sand correlates well with the supply, demand and pricing forecast for NWS operations such as Piranha and Taylor.

9.2 Appalachian Basin (Marcellus/Utica Play) and Niobrara Basin

Although smaller in size than the Permian energy fields, the Appalachian and Niobrara (or Niobrara-DJ) Basins are substantial natural gas and oil plays in North America. Unlike the Permian, the Appalachian and Niobrara import the vast majority of the frac sand, as very few notable in-basin sand operations exist. The Taylor Mine is advantaged, transportation wise to the Appalachian and Niobrara basins and there are few substitutes for its NWS products.

Following the energy downturn in 2019 and then Covid shutdown in 2020, the basin wellfield activity appears to be rebounding. Horizontal rigs have stabilized over the past two years as can be seen on Figure 9.4, but gas production per rig is substantially higher. Energy companies are drilling longer laterals and optimizing each well pad becoming more efficient from a cost perspective and overall natural gas production is stable as can be seen from Figure 9.5.

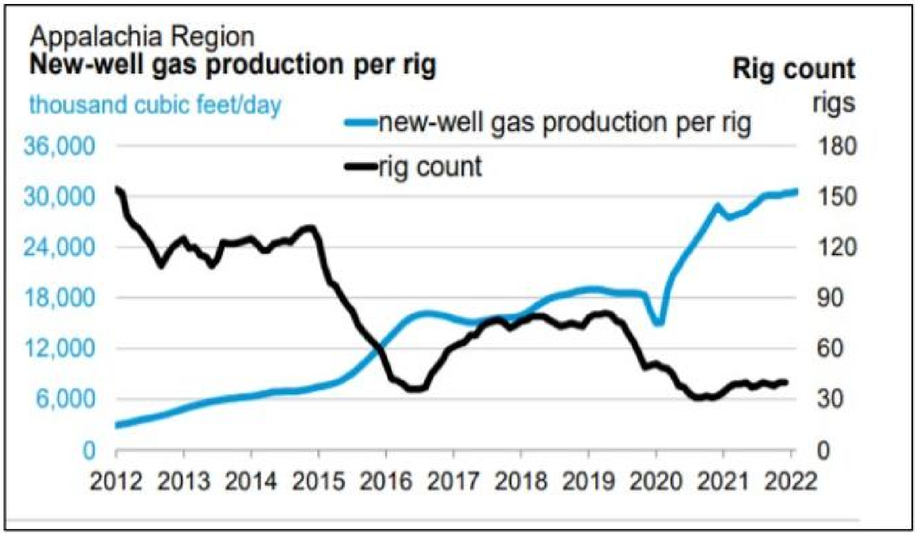

Figure 9.4: Appalachian Rig Count and Production per Rig (Source: EIA)

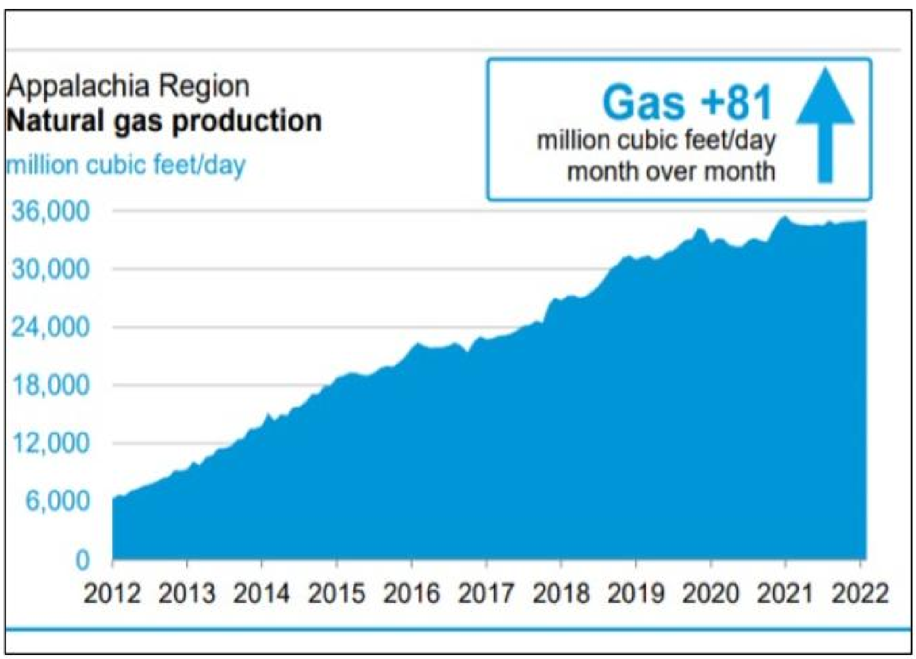

Figure 9.5: Appalachian Gas Production (Source: EIA)

Similarly, the Niobrara basin has seen a rebound in rig count since the Covid shutdown. Both gas and oil rig counts have risen but productivity per well has decreased as can be seen in Figure 9.6.

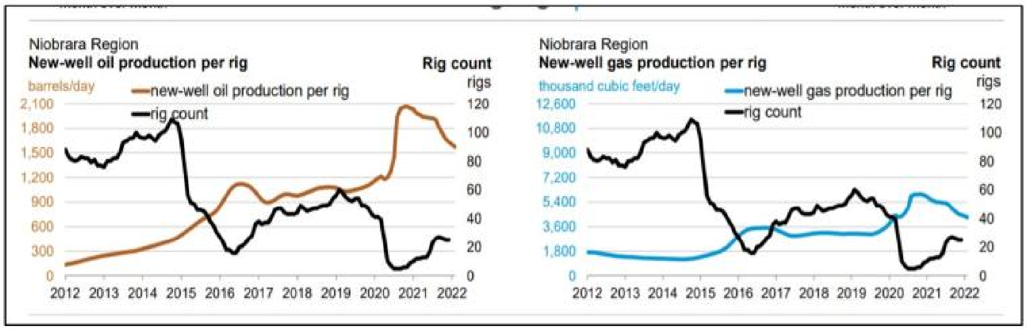

Figure 9.6: Niobrara Oil and Gas Rig Count and Productivity (Source: EIA)

Overall oil and gas production remains relatively flat in the basin, but more wells are being drilled to maintain this capacity. Figure 9.7 illustrates the overall yearly gas and oil production in the basin.

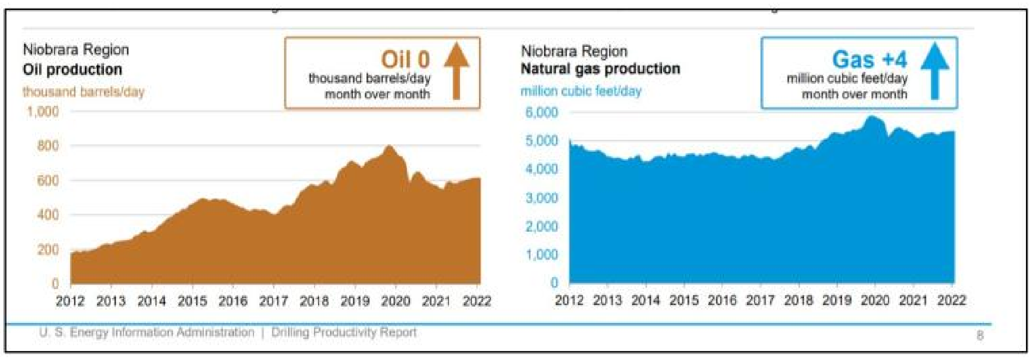

Figure 9.7: Niobrara Oil and Gas Production (Source: EIA)

Having survived the challenging environment of 2019 and 2020, Mammoth's operations should continue to prove viable into the future notwithstanding a sustained and significant energy price collapse. Their low-cost mining scheme, advantaged transport to select basins, and high-quality product help to create an advantage compared with other NWS producers.

10.0 CAPITAL, REVENUES, AND OPERATING COSTS

10.1 Introduction

This chapter will contain two main sections, one for the Piranha operation and one for the Taylor operation. Each section will address similar topics in their respective subsections.

10.2 Piranha Operation

10.2.1 Projected Production, Sales, and Costs

BOYD was provided historical financial and production data, as well as production, sales, and CapEx projections for the Piranha operation. Forecasted financial data, product pricing, and costs are in 2021 constant dollars. BOYD opines that the production and financial projections are reasonable and are likely to be within ± 20% accuracy level.

10.2.1.1 Production and Sales Projections

Table 10.1 below, presents frac sand production and sales projections for the period 2022 through 2026.

Table 10.1: Piranha Production Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
ROM Production (000)	853	853	853	853	853
Wet Plant Feed	853	853	853	853	853
Processing Recovery (%)	82.8	82.8	82.8	82.8	82.8
Wet Plant Product	706	706	706	706	706
Dry Plant Feed	706	706	706	706	706
Processing Recovery (%)	95.0	95.0	95.0	95.0	95.0
Dry Plant Product	671	671	671	671	671

Annual Forecasted annual ROM production is based on the dry plant producing 671,000 tons per year of saleable product after a processing (wet and dry processing plant) loss of approximately 21%, as discussed in Chapter 6. Forecasted dry processing plant production is within the operation's current infrastructure capacities and capabilities.

The dry processing plant is projected to produce a product mix of approximately 84% for 20/70-mesh products and approximately 16% for 70/140-mesh (100-mesh) product. The percent split is based on the product tons by mesh size for the frac sand reserves discussed in Chapter 5.

The sales price forecasts, by product, in Table 10.2 are based on price projections provided by Mammoth. Piranha's short term sales volume forecast did not include 100-mesh sales. BOYD projected that 100-mesh sales would begin in Year 2024 and ramp up from 11,000 tons per year to 107,000 tons per year by Year 2029, which represents 100% of the 100-mesh dry plant product. We opine that these volumes and prices are reasonable projections.

Table 10.2: Piranha Sales Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Tons Sold (000)	564	564	575	585	607
20/70-Mesh	564	564	564	564	564
70/140-Mesh (100-Mesh)	-	-	11	21	43
Revenues ($000)	10,485	10,485	10,650	10,800	11,130
Product Pricing ($ per ton sold)					
Weighted Average Price	18.59	18.59	18.52	18.46	18.34
20/70-Mesh	18.59	18.59	18.59	18.59	18.59
70/140-Mesh (100-Mesh)	-	-	15.00	15.00	15.00

10.2.1.2 Cash Cost of Goods Sold Projections

Table 10.3 below, presents the cash Cost of Goods Sold (COGS) projections for the period 2022 through 2026. BOYD prepared the operating cash cost projections, which are based on historical cost data provided by Mammoth. The operating cash costs include the following cost categories, sand mining expense, wet plant expense, hauling/trucking cost related to the transport of wet plant product to the off-site dry plant, dry plant expense, origin loadout, and plant overhead costs. BOYD considers these estimates to be reasonable, based on our experience with such operations.

Table 10.3: Piranha Annual Cash COGS Projections

	Summary Cash Cost of Goods Sold ($000)				
	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Cash Operating Expense	8,579	8,579	8,583	8,587	8,596
Royalty	65	65	75	76	79
SG&A	1,232	1,232	1,232	1,232	1,232
Final Reclamation Escrow	24	24	24	25	26
Total Cash Cost of Goods Sold	9,900	9,900	9,914	9,920	9,933

Royalty expense is paid to the Town of Dovre. The term of the agreement is until (a) Piranha has completed all Nonmetallic Mining Operations in the town, or (b) March 31, 2038.

Estimated SG&A is based on current year actual financial information provided by Mammoth to BOYD for the Piranha operation.

Mammoth provided BOYD with the final reclamation estimate, or Asset Retirement Obligation (ARO), of about $1.56 million for the operation. BOYD calculated annual per ton accrual to be slightly more than $0.04 per ton sold to recognize the estimated expense over the life of the Piranha operation.

Table 10.4 below, presents the above table's cost projections on a cost per ton sold basis for the period 2022 through 2026.

Table 10.4: Piranha Annual $ per Ton Sold Cash Cost Projections

	Summary Cash Cost of Goods Sold ($ per ton sold)				
	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Cash Operating Expense	15.17	15.17	14.88	14.64	14.12
Royalty	0.12	0.12	0.13	0.13	0.13
SG&A	2.18	2.18	2.14	2.11	2.03
Final Reclamation Escrow	0.04	0.04	0.04	0.04	0.04
Total Cash Cost of Goods Sold	17.51	17.51	17.19	16.92	16.32

10.2.1.3 Projected Capital Expenditures

Mammoth provided BOYD with their projected sustaining CapEx, for Years 2022 and 2023. Post Year 2023 sustaining CapEx for Piranha was projected by BOYD to be $0.75 per ton sold.

10.3 Taylor Operation

10.3.1 Projected Production, Sales, and Costs

BOYD was provided historical financial and production data, as well as production, sales, and CapEx projections for the Taylor operation. Forecasted financial data, product pricing, and costs are in 2021 constant dollars. BOYD opines that the production and financial projections are reasonable and are likely to be within ± 20% accuracy level.

10.3.1.1 Production and Sales Projections

Table 10.5 below, presents frac sand production and sales projections for the period 2022 through 2026.

Table 10.5: Taylor Production Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
ROM Production (000)	875	875	875	875	875
Wet Plant Feed	875	875	875	875	875
Processing Recovery (%)	76.8	76.8	76.8	76.8	76.8
Wet Plant Product	673	673	673	673	673
Dry Plant Feed	673	673	673	673	673
Processing Recovery (%)	95.0	95.0	95.0	95.0	95.0
Dry Plant Product	639	639	639	639	639

Forecasted annual ROM production is based on the dry plant producing 639,000 tons per year of saleable product after a processing (wet and dry processing plant) loss of approximately 27%, as discussed in Chapter 6. Forecasted dry processing plant production is within the operation's current infrastructure capacities and capabilities.

The dry processing plant is projected to produce a product mix of approximately 74% for 20/70-mesh products and approximately 26% for 70/140-mesh (100-mesh product). The percent split is based on the product tons by mesh size for the frac sand reserves discussed in Chapter 5.

The sales price forecasts, by product, in Table 10.6 are based on price projections provided by Mammoth. Taylor's short term sales volume forecast included reduced 70/140-mesh (100-mesh) sales. BOYD projected that 100-mesh sales would ramp up from 61,000 tons per year in Year 2022 to 167,000 tons per year by Year 2029, which represents 100% of the 100-mesh dry plant product. We opine that these volumes and prices are reasonable projections.

Table 10.6: Taylor Sales Projections

	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Tons Sold (000)	533	533	539	539	564
20/70-Mesh	472	472	472	472	472
70/140-Mesh (100-Mesh)	61	61	67	67	92
Revenues ($000)	10,515	10,515	10,605	10,605	10,980
Product Pricing ($ per ton sold)					
Weighted Average Price	19.73	19.73	19.68	19.68	19.47
20/70-Mesh	20.34	20.34	20.34	20.34	20.34
70/140-Mesh (100-Mesh)	15.00	15.00	15.00	15.00	15.00

10.3.1.2 Cash Cost of Goods Sold Projections

Table 10.7 below, presents the cash COGS projections for the period 2022 through 2026. BOYD prepared the operating cash cost projections, which are based on historical cost data provided by Mammoth. The operating cash costs include the following cost categories, sand mining expense, wet plant expense, dry plant expense, trucking dry plant product to the loadout, off-site rail loadout, and plant overhead costs. BOYD considers these estimates to be reasonable, based on our experience with such operations.

Table 10.7: Taylor Annual Cash COGS Projections

	Summary Cash Cost of Goods Sold ($000)				
	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Cash Operating Expense	6,947	6,947	6,961	6,961	7,019
SG&A	1,742	1,742	1,742	1,742	1,742
Final Reclamation Escrow	48	48	48	48	51
Total Cash Cost of Goods Sold	8,737	8,737	8,752	8,752	8,811

Estimated SG&A is based on current year actual financial information provided by Mammoth to BOYD for the Taylor operation.

Mammoth provided BOYD with the final reclamation estimate of about $2.13 million for the operation. BOYD calculated annual per ton accrual to be slightly more than $0.09 per ton sold to recognize the estimated expense over the life of the Taylor operation.

Table 10.8 below, presents the above table's cost projections on a cost per ton sold basis for the period 2022 through 2026.

Table 10.8: Taylor Annual $ per Ton Sold Cash Cost Projections

	Summary Cash Cost of Goods Sold ($ per ton sold)				
	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Cash Operating Expense	13.03	13.03	12.92	12.92	12.44
SG&A	3.27	3.27	3.23	3.23	3.09
Final Reclamation Escrow	0.09	0.09	0.09	0.09	0.09
Total Cash Cost of Goods Sold	16.39	16.39	16.24	16.24	15.62

10.3.1.3 Projected Capital Expenditures

Mammoth provided BOYD with their projected sustaining CapEx, for Years 2022 and 2023. Post Year 2023 sustaining CapEx for Taylor was projected by BOYD to be $0.80 per ton sold.

11.0 ECONOMIC ANALYSIS

11.1 Introduction

This chapter will contain two main sections, one for the Piranha operation and one for the Taylor operation. Each section will address similar topics in their respective subsections.

Cash flow projections, for the Piranha and Taylor operations, have been generated from their respective proposed LOM production schedules and revenues, COGS, and CapEx estimates discussed in Chapter 10. A summary of the key assumptions used is provided below.

- LOM ROM frac sand tons and product tons sold were based on the respective total frac sand reserve estimates discussed in Chapter 6 of this report. The Piranha operation is estimated to be depleted in Year 2078 and the Taylor operation is estimated to be depleted in Year 2059.

- Forecasted revenues, at the respective on-site loadouts (mine gate), are based on sales of both 20/70 and 70/140-mesh (100-mesh) size products to be delivered to Mammoth's customers.

- Operating and Other Costs (as discussed in Chapter 10).
  - Sand mining expenses.
  - Wet plant expenses.
  - Wet plant product to dry plant trucking expenses.
  - Dry plant and loadout expenses.
  - Plant overhead expenses.
  - Royalty expense (Piranha only).
  - SG&A expense.

- Reclamation costs include:
  - Final reclamation cost to reclaim each respective site.

- Capital Expenditures (as discussed in Chapter 10) include:
  - Sustaining/Maintenance.

- Computation of Federal and State Income Taxes:
  - Mammoth Energy is a corporation with multiple lines of businesses, as well as operating companies. The Piranha and Taylor operations are a subset of one of their business groups.

- As such, a simplified after-tax computation was performed, based on the following:
  - Tax rates used: federal tax rate of 21%, and Wisconsin state tax rate of 7.9%.
  - Taxable income was Revenues less Cash COGS. Depreciation expense, from existing fixed assets and new fixed assets, was not included in COGS, and in the tax computation.
  - Operating losses, if any, are carried forward in the tax computation considered in tax computation.

- After-Tax NPVs:
  - Simplified After-Tax cash flows were discounted using several rates.
  - This report will only comment on whether the After-Tax NPV was positive or negative. No value will be presented.

11.2 Piranha Operation

11.2.1 Economic Analysis

BOYD prepared an economic analysis, as of January 1, 2022, for the Piranha Operation using the production, sales, and financial projections presented in this report. Our analysis confirms that the operation generates positive cash flows (based on a 12% discount rate), on a pre-tax and after-tax basis, that supports the statement of frac sand reserves herein.

11.2.2 Cash Flow Analysis

Table 11.1 below presents the pre-tax cash flow projections based on the proposed LOM production schedule and revenue, COGS, and CapEx and other estimates discussed above for the Piranha operation.

Table 11.1: Summary Pre-Tax Cash Flow Statement

	Summary Cash Flow Statement ($ 000)						
	2022 to 2031	2032 to 2041	2042 to 2051	2052 to 2061	2062 to 2071	2072 to 2078	Total
Total Tons Sold (000)	6,186	6,710	6,710	6,710	6,710	4,264	37,290
Revenues	113,038	120,898	120,898	120,898	120,898	76,755	673,383
COGS	99,407	99,889	99,493	99,828	100,164	64,876	562,396
CapEx	4,191	5,033	5,033	5,033	5,033	2,768	27,089
Net Pre-Tax Cash Flow	9,440	15,977	16,372	16,037	15,701	9,111	83,898

DCF-NPV on a pre-tax and after-tax basis, using discount rates of 10%, 12%, and 15%, were calculated utilizing the cash flows above. The DCF-NPV values used mid-year discounting and all cash flows were on a constant dollar basis.

The pre-tax DCF-NPV ranges from approximately $6.9 million to $11.8 million. The after-tax DCF-NPVs were all positive. Table 11.2 summarizes the results of the pre-tax analyses:

Table 11.2: DCF-NPV

	DCF-NPV ($ 000)		
	10%	12%	15%
Pre-Tax	11,760	9,310	6,899

Refer to Table 11.3 for the detailed LOM cash flow analysis and corresponding pre-tax DCF-NPV analyses at a 12% discount rate.

BOYD notes that the NPV estimate was made for purposes of confirming the economic viability of the reported frac sand reserves and not for purposes of valuing Mammoth, the Piranha operation, or its assets. IRR and project payback were not calculated, as there was no initial investment considered in the financial model. Risk is subjective, as such, BOYD recommends that each reader should evaluate the project based on their own investment criteria.

11.2.3 Pre-Tax Sensitivity Analyses

Sensitivity analysis for the pre-tax cash flows considering changes to revenues and COGS/CapEx were prepared using discount rates of 10%, 12%, and 15%. Revenues were adjusted in increments of 5% and range from minus 20% to plus 20% base revenues. Costs were adjusted in increments of 5% and range from minus 20% to plus 20% base costs.

The following three tables (Tables 11.4–11.6) summarize the results of the pre-tax sensitivity analyses performed, which utilize discount rates of 10%, 12%, and 15% and incorporate the changes to revenue and COGS/CapEx discussed above.

Table 11.4: Pre-Tax DCF-NPV at 10%

Pre-Tax DCF-NPV @ 10% (US$ millions)									
	Revenues								
	-20.0%	-15.0%	-10.0%	-5.0%	0.0%	5.0%	10.0%	15.0%	20.0%
-20.0%	9.3	15.3	21.3	27.3	33.3	39.3	45.3	51.3	57.3
-15.0%	3.9	9.9	15.9	21.9	27.9	33.9	39.9	45.9	51.9
-10.0%	(1.5)	4.5	10.5	16.5	22.5	28.5	34.5	40.5	46.5
-5.0%	(6.9)	(0.9)	5.1	11.1	17.1	23.1	29.1	35.1	41.1
0.0%	(12.2)	(6.2)	(0.2)	5.8	11.8	17.8	23.8	29.8	35.8
5.0%	(17.6)	(11.6)	(5.6)	0.4	6.4	12.4	18.4	24.4	30.4
10.0%	(23.0)	(17.0)	(11.0)	(5.0)	1.0	7.0	13.0	19.0	25.0
15.0%	(28.4)	(22.4)	(16.4)	(10.4)	(4.4)	1.6	7.6	13.6	19.6
20.0%	(33.8)	(27.8)	(21.8)	(15.7)	(9.7)	(3.7)	2.3	8.3	14.3

TABLE 11.3

PRE-TAX AND AFTER-TAX CASH FLOW ANALYSIS
MAMMOTH ENERGY - PIRANHA OPERATION
Barron County, Wisconsin
Prepared For
MAMMOTH ENERGY SERVICES
By
John T. Boyd Company
Mining and Geological Consultants
February 2022

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032 to 2041	2042 to 2051	2052 to 2061	2062 to 2071	2072 to 2078	Total
Production Statistics (Tons 000):																
ROM Production Property	853	853	853	853	853	853	853	853	853	853	8,527	8,527	8,527	8,527	5,419	48,052
Processing Statistics (Tons 000):																
Wet Plant Feed	853	853	853	853	853	853	853	853	853	853	8,527	8,527	8,527	8,527	5,419	48,052
Processing Recovery (%)	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8	82.8
Wet Plant Product	706	706	706	706	706	706	706	706	706	706	7,063	7,063	7,063	7,063	4,488	39,803
Dry Plant Feed	706	706	706	706	706	706	706	706	706	706	7,063	7,063	7,063	7,063	4,488	39,803
Processing Recovery (%)	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0
Dry Plant Product	671	671	671	671	671	671	671	671	671	671	6,710	6,710	6,710	6,710	4,264	37,814
Overall Processing Recovery (%)	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7
Sales and Financial Data:																
Saleable Product Tons Sold (000):																
20/70-Mesh	564	564	564	564	564	564	564	564	564	564	5,640	5,640	5,640	5,640	3,564	31,764
100-Mesh	-	-	11	21	43	64	86	107	107	107	1,070	1,070	1,070	1,070	700	5,526
Total Tons Sold	564	564	575	585	607	628	650	671	671	671	6,710	6,710	6,710	6,710	4,264	37,290
Product Pricing ($ per ton)																
20/70-Mesh	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59	18.59
100-Mesh	-	-	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Weighted Average	18.59	18.59	18.52	18.46	18.34	18.22	18.12	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.00	18.06
Revenues ($ 000)																
20/70-Mesh	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	10,485	104,848	104,848	104,848	104,848	66,255	590,493
100-Mesh	-	-	165	315	645	960	1,290	1,605	1,605	1,605	16,050	16,050	16,050	16,050	10,500	82,890
Total Sales Revenues	10,485	10,485	10,650	10,800	11,130	11,445	11,775	12,090	12,090	12,090	120,898	120,898	120,898	120,898	76,755	673,383
COGS ($ 000):																
Cash Operating Expense	8,554	8,554	8,558	8,562	8,571	8,580	8,588	8,597	8,597	8,597	86,303	86,639	86,974	87,310	56,072	489,056
$ per ROM ton	10.03	10.03	10.04	10.04	10.05	10.06	10.07	10.08	10.08	10.08	10.12	10.16	10.20	10.24	10.35	10.18
$ per ton sold	15.17	15.17	14.88	14.64	14.12	13.66	13.21	12.81	12.81	12.81	12.86	12.91	12.96	13.01	13.15	13.11
Royalty	65	65	75	76	79	82	85	97	97	97	731	-	-	-	-	1,549
$ per ton sold	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.15	0.15	0.15	0.11	-	-	-	-	0.04
S,G&A	1,232	1,232	1,232	1,232	1,232	1,232	1,232	1,232	1,232	1,232	12,320	12,320	12,320	12,320	8,624	70,224
$ per ton sold	2.18	2.18	2.14	2.11	2.03	1.96	1.90	1.84	1.84	1.84	1.84	1.84	1.84	1.84	2.02	1.88
Final Reclamation Escrow	24	24	24	25	25	26	27	28	28	28	282	282	282	282	180	1,567
$ per ton sold	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total COGS	9,875	9,875	9,889	9,895	9,908	9,920	9,932	9,954	9,954	9,954	99,637	99,241	99,576	99,912	64,876	562,396
$ per ton sold	17.51	17.51	17.20	16.91	16.32	15.80	15.28	14.83	14.83	14.83	14.85	14.79	14.84	14.89	15.21	15.08
EBITDA	610	610	760	905	1,222	1,525	1,843	2,136	2,136	2,136	21,261	21,657	21,321	20,986	11,879	110,987
$ per ton sold	1.08	1.08	1.32	1.55	2.01	2.43	2.83	3.18	3.18	3.18	3.17	3.23	3.18	3.13	2.79	2.98
CapEx ($ 000):																
Total CapEx	345	509	345	351	364	377	390	503	503	503	5,033	5,033	5,033	5,033	2,768	27,089
Net Pre-Tax Cash Flow	265	101	415	554	858	1,148	1,453	1,632	1,632	1,632	16,229	16,624	16,289	15,953	9,111	83,898
DCF-NPV Analysis:																
Pre-Tax Discounted Cash Flows at 12%	251	85	313	372	515	616	695	698	623	556	3,104	1,031	325	103	23	9,310
Cumulative Pre-Tax Discounted Cash Flows at 12%	251	336	649	1,021	1,537	2,152	2,848	3,545	4,168	4,725	7,829	8,859	9,184	9,287	9,310	

Table 11.5: Pre-Tax DCF-NPV at 12%

Pre-Tax DCF-NPV @ 12% (US$ millions)										
		Revenues								
		-20.0%	-15.0%	-10.0%	-5.0%	0.0%	5.0%	10.0%	15.0%	20.0%
Ex	-20.0%	7.3	12.3	17.4	22.4	27.4	32.5	37.5	42.5	47.5
	-15.0%	2.8	7.8	12.8	17.9	22.9	27.9	33.0	38.0	43.0

COGS and CapE									
-10.0%	(1.7)	3.3	8.3	13.3	18.4	23.4	28.4	33.5	38.5
-5.0%	(6.3)	(1.2)	3.8	8.8	13.8	18.9	23.9	28.9	33.9
0.0%	(10.8)	(5.8)	(0.7)	4.3	9.3	14.3	19.4	24.4	29.4
5.0%	(15.3)	(10.3)	(5.3)	(0.2)	4.8	9.8	14.8	19.9	24.9
10.0%	(19.9)	(14.8)	(9.8)	(4.8)	0.3	5.3	10.3	15.3	20.4
15.0%	(24.4)	(19.4)	(14.3)	(9.3)	(4.3)	0.7	5.8	10.8	15.8
20.0%	(28.9)	(23.9)	(18.9)	(13.8)	(8.8)	(3.8)	1.2	6.3	11.3

Table 11.6: Pre-Tax DCF-NPV at 15%

Pre-Tax DCF-NPV @ 15% (US$ millions)									
	Revenues								
COGS and CapEx	-20.0%	-15.0%	-10.0%	-5.0%	0.0%	5.0%	10.0%	15.0%	20.0%
-20.0%	5.4	9.5	13.5	17.5	21.6	25.6	29.7	33.7	37.8
-15.0%	1.7	5.8	9.8	13.9	17.9	22.0	26.0	30.0	34.1
-10.0%	(1.9)	2.1	6.2	10.2	14.2	18.3	22.3	26.4	30.4
-5.0%	(5.6)	(1.6)	2.5	6.5	10.6	14.6	18.7	22.7	26.7
0.0%	(9.3)	(5.2)	(1.2)	2.9	6.9	10.9	15.0	19.0	23.1
5.0%	(12.9)	(8.9)	(4.9)	(0.8)	3.2	7.3	11.3	15.4	19.4
10.0%	(16.6)	(12.6)	(8.5)	(4.5)	(0.4)	3.6	7.6	11.7	15.7
15.0%	(20.3)	(16.2)	(12.2)	(8.2)	(4.1)	(0.1)	4.0	8.0	12.1
20.0%	(24.0)	(19.9)	(15.9)	(11.8)	(7.8)	(3.7)	0.3	4.3	8.4

11.3 Taylor Operation

11.3.1 Economic Analysis

BOYD prepared an economic analysis, as of January 1, 2022, for the Taylor Operation using the production, sales, and financial projections presented in this report. Our analysis confirms that the operation generates positive cash flows (based on a 12% discount rate), on a pre-tax and after-tax basis, that supports the statement of frac sand reserves herein.

11.3.2 Cash Flow Analysis

Table 11.7 below presents the pre-tax cash flow projections based on the proposed LOM production schedule and revenue, COGS, and CapEx and other estimates discussed above for the Taylor operation.

Table 11.7: Summary Pre-Tax Cash Flow Statement

	Summary Cash Flow Statement ($ 000)				
	2022 to 2031	2032 to 2041	2042 to 2051	2052 to 2059	Total
Total Tons Sold (000)	5,828	6,390	6,390	5,107	23,715
Revenues	112,625	121,055	121,055	96,747	451,482
COGS	88,563	90,225	90,545	72,647	341,979
CapEx	7,393	5,112	5,112	3,323	20,939
Net Pre-Tax Cash Flow	16,670	25,718	25,398	20,778	88,563

DCF-NPV on a pre-tax and after-tax basis, using discount rates of 10%, 12%, and 15%, were calculated utilizing the cash flows above. The DCF-NPV values used mid-year discounting and all cash flows were on a constant dollar basis.

The pre-tax DCF-NPV ranges from approximately $11.5 million to $18.8 million. The after-tax DCF-NPVs were all positive. Table 11.8 summarizes the results of the pre-tax analyses:

Table 11.8: DCF-NPV

	DCF-NPV ($ 000)		
	10%	12%	15%
Pre-Tax	18,827	15,221	11,507

Refer to Table 11.9 for the detailed LOM cash flow analysis and corresponding pre-tax DCF-NPV analyses at a 12% discount rate.

BOYD notes that the NPV estimate was made for purposes of confirming the economic viability of the reported frac sand reserves and not for purposes of valuing Mammoth, the Taylor operation, or its assets. IRR and project payback were not calculated, as there was no initial investment considered in the financial model. Risk is subjective, as such, BOYD recommends that each reader should evaluate the project based on their own investment criteria.

TABLE 11.9

PRE-TAX CASH FLOW ANALYSIS
MAMMOTH ENERGY - TAYLOR OPERATION
Jackson County, Wisconsin
Prepared For
MAMMOTH ENERGY SERVICES
By
John T. Boyd Company
Mining and Geological Consultants
February 2022

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032 to 2041	2042 to 2051	2052 to 2059	Total
Production Statistics (Tons 000):														
ROM Production off Fee Property	875	875	875	875	875	875	875	875	875	875	8,754	8,754	6,995	33,256
Processing Statistics (Tons 000):														
Wet Plant Feed	875	875	875	875	875	875	875	875	875	875	8,754	8,754	6,995	33,256
Processing Recovery (%)	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.9	76.8
Wet Plant Product	673	673	673	673	673	673	673	673	673	673	6,726	6,726	5,376	25,555
Dry Plant Feed	673	673	673	673	673	673	673	673	673	673	6,726	6,726	5,376	25,555
Processing Recovery (%)	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0
Dry Plant Product	639	639	639	639	639	639	639	639	639	639	6,390	6,390	5,107	24,277
Overall Processing Recovery (%)	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0
Sales and Financial Data:														
Saleable Product Tons Sold (000):														
20/70-Mesh	472	472	472	472	472	472	472	472	472	472	4,720	4,720	3,772	17,932
70/140-Mesh (100-Mesh)	61	61	67	67	92	117	142	167	167	167	1,670	1,670	1,335	5,783
Total Tons Sold	533	533	539	539	564	589	614	639	639	639	6,390	6,390	5,107	23,715
Product Pricing ($ per ton)														
20/70-Mesh	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34	20.34
70/140-Mesh (100-Mesh)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Weighted Average	19.73	19.73	19.68	19.68	19.47	19.28	19.11	18.94	18.94	18.94	18.94	18.94	18.94	19.04
Revenues ($ 000)														
20/70-Mesh	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600	96,005	96,005	76,722	364,737
70/140-Mesh (100-Mesh)	915	915	1,005	1,005	1,380	1,755	2,130	2,505	2,505	2,505	25,050	25,050	20,025	86,745
Total Sales Revenues	10,515	10,515	10,605	10,605	10,980	11,355	11,730	12,105	12,105	12,105	121,055	121,055	96,747	451,482
COGS ($ 000):														
Cash Operating Expense	6,947	6,947	6,961	6,961	7,019	7,076	7,134	7,191	7,191	7,191	72,232	72,551	58,252	273,655
$ per ROM ton	7.94	7.94	7.95	7.95	8.02	8.08	8.15	8.22	8.22	8.22	8.25	8.29	8.33	8.23
$ per ton sold	13.03	13.03	12.92	12.92	12.44	12.01	11.62	11.25	11.25	11.25	11.30	11.35	11.41	11.54
S,G&A	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	17,420	17,420	13,936	66,196
$ per ton sold	3.27	3.27	3.23	3.23	3.09	2.96	2.84	2.73	2.73	2.73	2.73	2.73	2.73	2.79
Final Reclamation Escrow	48	48	48	48	51	53	55	57	57	57	573	573	459	2,128
$ per ton sold	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Total COGS	8,737	8,737	8,752	8,752	8,811	8,871	8,931	8,991	8,991	8,991	90,225	90,545	72,647	341,979
$ per ton sold	16.39	16.39	16.24	16.24	15.62	15.06	14.55	14.07	14.07	14.07	14.12	14.17	14.22	14.42
EBITDA	1,778	1,778	1,854	1,854	2,169	2,484	2,800	3,115	3,115	3,115	30,830	30,510	24,101	109,503
$ per ton sold	3.34	3.34	3.44	3.44	3.85	4.22	4.56	4.87	4.87	4.87	4.82	4.77	4.72	4.62
CapEx ($ 000):														
Total CapEx	1,500	2,083	431	431	451	471	491	511	511	511	5,112	5,112	3,323	20,939
Net Pre-Tax Cash Flow	278	(305)	1,423	1,423	1,718	2,013	2,308	2,604	2,604	2,604	25,718	25,398	20,778	88,563
DCF-NPV Analysis:														
Pre-Tax Discounted Cash Flows at 12%	263	(257)	1,072	957	1,032	1,079	1,105	1,113	994	887	4,951	1,574	451	15,221
Cumulative Pre-Tax Discounted Cash Flows at 12%	263	6	1,077	2,034	3,066	4,145	5,250	6,363	7,357	8,244	13,196	14,770	15,221	

11.3.3 Pre-Tax Sensitivity Analyses

Sensitivity analysis for the pre-tax cash flows considering changes to revenues and COGS/CapEx were prepared using discount rates of 10%, 12%, and 15%. Revenues were adjusted in increments of 5% and range from minus 20% to plus 20% base revenues. Costs were adjusted in increments of 5% and range from minus 20% to plus 20% base costs.

The following three tables (Tables 11.10–11.12) summarize the results of the pre-tax sensitivity analyses performed, which utilize discount rates of 10%, 12%, and 15% and incorporate the changes to revenue and COGS/CapEx discussed above.

Table 11.10: Pre-Tax DCF-NPV at 10%

Pre-Tax DCF-NPV @ 10% (US$ millions)									
	Revenues								
COGS and CapEx	-20.0%	-15.0%	-10.0%	-5.0%	0.0%	5.0%	10.0%	15.0%	20.0%
-20.0%	15.1	20.9	26.8	32.6	38.5	44.3	50.2	56.0	61.9
-15.0%	10.2	16.0	21.9	27.7	33.6	39.4	45.3	51.1	57.0
-10.0%	5.2	11.1	16.9	22.8	28.6	34.5	40.4	46.2	52.1
-5.0%	0.3	6.2	12.0	17.9	23.7	29.6	35.4	41.3	47.1
0.0%	(4.6)	1.3	7.1	13.0	18.8	24.7	30.5	36.4	42.2
5.0%	(9.5)	(3.6)	2.2	8.1	13.9	19.8	25.6	31.5	37.3
10.0%	(14.4)	(8.5)	(2.7)	3.2	9.0	14.9	20.7	26.6	32.4
15.0%	(19.3)	(13.5)	(7.6)	(1.8)	4.1	9.9	15.8	21.7	27.5
20.0%	(24.2)	(18.4)	(12.5)	(6.7)	(0.8)	5.0	10.9	16.7	22.6

Table 11.11: Pre-Tax DCF-NPV at 12%

Pre-Tax DCF-NPV @ 12% (US$ millions)									
	Revenues								
COGS and CapEx	-20.0%	-15.0%	-10.0%	-5.0%	0.0%	5.0%	10.0%	15.0%	20.0%
-20.0%	12.2	17.1	22.1	27.0	32.0	36.9	41.9	46.9	51.8
-15.0%	8.0	12.9	17.9	22.8	27.8	32.8	37.7	42.7	47.6
-10.0%	3.8	8.7	13.7	18.7	23.6	28.6	33.5	38.5	43.4
-5.0%	(0.4)	4.6	9.5	14.5	19.4	24.4	29.3	34.3	39.2
0.0%	(4.6)	0.4	5.3	10.3	15.2	20.2	25.1	30.1	35.0
5.0%	(8.8)	(3.8)	1.1	6.1	11.0	16.0	20.9	25.9	30.8
10.0%	(13.0)	(8.0)	(3.1)	1.9	6.8	11.8	16.7	21.7	26.7
15.0%	(17.2)	(12.2)	(7.3)	(2.3)	2.6	7.6	12.5	17.5	22.5
20.0%	(21.4)	(16.4)	(11.5)	(6.5)	(1.6)	3.4	8.4	13.3	18.3

Table 11.12: Pre-Tax DCF-NPV at 15%

Pre-Tax DCF-NPV @ 15% (US$ millions)										
		Revenues								
		-20.0%	-15.0%	-10.0%	-5.0%	**0.0%**	5.0%	10.0%	15.0%	20.0%
COGS and CapEx	-20.0%	9.2	13.2	17.2	21.2	25.3	29.3	33.3	37.3	41.3
	-15.0%	5.8	9.8	13.8	17.8	21.8	25.8	29.8	33.9	37.9
	-10.0%	2.3	6.3	10.4	14.4	18.4	22.4	26.4	30.4	34.4
	-5.0%	(1.1)	2.9	6.9	10.9	14.9	19.0	23.0	27.0	31.0
	0.0%	(4.5)	(0.5)	3.5	7.5	**11.5**	15.5	19.5	23.5	27.6
	5.0%	(8.0)	(4.0)	0.0	4.1	8.1	12.1	16.1	20.1	24.1
	10.0%	(11.4)	(7.4)	(3.4)	0.6	4.6	8.6	12.7	16.7	20.7
	15.0%	(14.9)	(10.8)	(6.8)	(2.8)	1.2	5.2	9.2	13.2	17.2
	20.0%	(18.3)	(14.3)	(10.3)	(6.3)	(2.2)	1.8	5.8	9.8	13.8

12.0 PERMITTING AND COMPLIANCE

12.1 Permitting

The Piranha Mine's operations are predominantly regulated by a Barron County, Wisconsin Non-metallic Reclamation Permit which contains detailed reclamation plans for the property. Mine operators must submit annual reports to Barron County containing information on the reclamation status of their mines and pay annual fees based on the disturbed acres. They must also provide written certification that the reclamation plan is being followed. A reclamation bond is also required, and the amount is periodically updated based on the number of disturbed acres.

The Taylor Mine in Jackson County has similar requirements to those described above for mining and reclamation. The Jackson County Zoning, Planning and POWTS Department administers the mining program at Taylor.

Air emissions for both sites are regulated by the Wisconsin Department of Natural Resources, Bureau of Air Management. Mammoth monitors air emissions at both sites and has current permits.

12.2 Compliance

Mine safety is regulated by the federal government by MSHA as are all surface mining operations. MSHA inspects the facilities a minimum of twice yearly. Mammoth's safety record compares favorably with its regional peers.

Based on our review of information provided by Mammoth and available public information, it is BOYD's opinion that the Taylor and Piranha record of compliance with applicable mining, water quality, and environmental regulations is generally acceptable for that of the industry. BOYD is not aware of any regulatory violation or compliance issue which would materially impact the frac sand reserve estimates at either operation.

13.0 INTERPRETATION AND CONCLUSIONS

13.1 Findings

Based on our independent technical review and geoscientific study of the Taylor and Piranha mines, BOYD concludes:

- Sufficient data have been obtained through the site exploration and sampling program and mining operations to support the geological interpretations of seam thickness, grain size distribution and API quality for the portions of the sand underlying the controlled property. The data are of sufficient quantity and reliability to reasonably support the sand resource and sand reserve estimates in this technical report summary.
- Estimates of proppant sand reserves reported herein are reasonably and appropriately supported by technical studies, which consider mining plans, revenue, and operating and capital cost estimates.
- The 62 million product tons of frac sand reserves (as of December 31, 2021) estimated for the two mines (Piranha at 38 million and Taylor at 24 million) are economically extractable under reasonable expectations of market volumes and pricing for proppant sand products, estimated operation costs, and capital expenditures.
- There are no other relevant data or information material to the Piranha or Taylor mines that is necessary to make this technical report summary not misleading.

13.2 Significant Risks and Uncertainties

As with any mining project there are certain inherent risks associated with the overall operation of a facility. Mammoth has sufficiently mitigated operational risk through obtaining sufficient geologic sampling information and analysis for classifying the mineral reserve base. However, it should be noted that frac sand is generally marketed exclusively to the energy industry which has historically been a volatile industry.