



ANNUAL REPORT
TWENTY TWENTY-THREE



LETTER FROM EXECUTIVE CHAIRMAN MARTIN HOUSTON TO SHAREHOLDERS



APRIL 2024

Our global market

Global natural gas consumption has risen significantly over the last decade. Increasing demand for power generation is expected to drive the global LNG market for years to come; the world requires low-carbon energy to support future economic growth. At Tellurian, we will help overcome the global challenges of energy affordability, availability and security while reducing emissions.

Progress at Tellurian

2023 was a year of progress, and latterly, of board, management and strategic change at Tellurian. I took charge as non-executive Chairman in December, becoming Executive Chairman post year-end. We have restructured the executive team and appointed two Presidents with complementary but distinct areas of responsibility.

As a team, we have sharpened our focus on stability, financial discipline and execution, and are laser-focused on bringing Driftwood to financial investment decision. To this end, we have improved our balance sheet and liquidity position and widened our commercial aperture to give customers the full variety of options at market prices.

Our purpose is to provide secure, low-cost natural gas to a portfolio of global customers thereby creating value for our

shareholders. This year we have widened our outreach to current and potential global customers of US LNG to ensure Tellurian is well positioned to capitalize on market dynamics.

Construction of Driftwood LNG made steady progress with ~15,000 piles and concrete foundations in place for Phase 1.

We received a certificate from the Federal Energy Regulatory Commission (FERC) for Line 200 and Line 300, pipelines that will provide natural gas to key supply hubs near Driftwood LNG. The pipelines will be the first land use of electric powered technology from Baker Hughes, which provides for virtually zero emissions.

Tellurian Production LLC maintained stable production. In early 2024, we announced the potential sale of this business, which includes ~31,000 net acres in the prolific Louisiana Haynesville and Bossier shales, with interests in over 150 producing wells and 425 undeveloped locations. Current net production is ~140 million cubic feet per day.

As a business in a global marketplace, Tellurian is committed to producing our energy in a responsible and sustainable way, focusing our efforts on five key areas: safety, environment, community participation, corporate governance and development of our diverse workforce.

We advanced our work with the National Forest Foundation for nature-based carbon sequestration and have planted over three million trees in three years. In addition, we boosted tree seedling production by four million in six nurseries.

Tellurian produced its second ESG summary, which is available on our website and details our exemplary record of no lost-time safety incidents, sound governance and environmental performance.

Looking to the future

Looking ahead, our executive team has the experience, capabilities and structure to take Tellurian forward - and we have already seen the positive impact of this new leadership structure in a short period. I should like to thank our team for their enduring hard work and commitment, and I am grateful to you, our shareholders and stakeholders, for your continued support, feedback and investment.

A handwritten signature in blue ink that reads "Martin".

**MARTIN
HOUSTON**

Executive Chairman

**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, 2023

OR

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

For the transition period from _____ to _____

Commission File Number 001-5507



Tellurian Inc.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

06-0842255

(I.R.S. Employer Identification No.)

1201 Louisiana Street, Suite 3100, Houston, TX

(Address of principal executive offices)

77002

(Zip Code)

(832) 962-4000

(Registrant's telephone number, including area code)

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

Title of each class	Trading symbol	Name of each exchange on which registered
Common stock, par value \$0.01 per share	TELL	NYSE American LLC
8.25% Senior Notes due 2028	TELZ	NYSE American LLC

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	<input checked="" type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
		Emerging growth company	<input type="checkbox"/>

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

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

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant’s executive officers during the relevant recovery period pursuant to § 240.10D-1(b).

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 the voting and non-voting common equity held by non-affiliates of the registrant, as of June 30, 2023, the last business day of the registrant’s most recently completed second fiscal quarter, was approximately \$767,326 thousand, based on the per share closing sale price of \$1.41 on that date. Solely for purposes of this disclosure, shares of common stock held by executive officers and directors of the registrant as of such date have been excluded because such persons may be deemed to be affiliates. This determination of executive officers and directors as affiliates is not necessarily a conclusive determination for any other purpose.

782,393,431 shares of common stock were issued and outstanding as of February 8, 2024.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the 2024 annual meeting of stockholders, to be filed within 120 days after December 31, 2023, are incorporated by reference in Part III of this annual report on Form 10-K.

Tellurian Inc.

For the Fiscal Year Ended December 31, 2023

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Cautionary Information About Forward-Looking Statements

The information in this report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical facts, that address activity, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “contemplate,” “continue,” “could,” “estimate,” “expect,” “forecast,” “initial,” “intend,” “likely,” “may,” “plan,” “possible,” “potential,” “predict,” “project,” “proposed,” “should,” “will,” “would” and similar terms, phrases, and expressions are intended to identify forward-looking statements. These forward-looking statements relate to, among other things:

- our businesses and prospects and our overall strategy;
- planned or estimated capital expenditures;
- availability of liquidity and capital resources;
- our ability to obtain financing as needed and the terms of financing transactions, including for the Driftwood Project;
- the sale process of our upstream assets;
- revenues and expenses;
- progress in developing our projects and the timing of that progress;
- attributes and future values of the Company’s projects or other interests, operations or rights; and
- government regulations, including our ability to obtain, and the timing of, necessary governmental permits and approvals.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Factors that could cause actual results and performance to differ materially from any future results or performance expressed or implied by the forward-looking statements include, but are not limited to, the following:

- the uncertain nature of demand for and price of natural gas and LNG;
- risks related to shortages of LNG vessels worldwide;
- technological innovation which may render our anticipated competitive advantage obsolete;
- risks related to a terrorist or military incident involving an LNG carrier;
- changes in legislation and regulations relating to the LNG industry, including environmental laws and regulations that impose significant compliance costs and liabilities;
- governmental interventions in the LNG industry, including increases in barriers to international trade;
- uncertainties regarding our ability to maintain sufficient liquidity and attract sufficient capital resources to implement our projects;
- our limited operating history;
- our ability to attract and retain key personnel;
- risks related to doing business in, and having counterparties in, foreign countries;
- our reliance on the skill and expertise of third-party service providers;
- the ability of our vendors, customers and other counterparties to meet their contractual obligations;
- risks and uncertainties inherent in management estimates of future operating results and cash flows;
- our ability to maintain compliance with our debt arrangements;
- changes in competitive factors, including the development or expansion of LNG, pipeline and other projects that are competitive with ours;

- development risks, operational hazards and regulatory approvals and the ability to maintain such approvals;
- our ability to enter into and consummate planned financing and other transactions;
- risks related to pandemics or disease outbreaks;
- risks of potential impairment charges and reductions in our reserves; and
- risks and uncertainties associated with litigation matters.

The forward-looking statements in this report speak as of the date hereof. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document, the terms listed below have the following meanings:

ASC	Accounting Standards Codification
Bcf	Billion cubic feet of natural gas
Bcfe	Billion cubic feet of natural gas equivalent volumes using a ratio of 6 Mcf to 1 barrel of liquid
Condensate	Hydrocarbons that exist in a gaseous phase at original reservoir temperature and pressure, but when produced, are in the liquid phase at surface pressure and temperature
DD&A	Depreciation, depletion, and amortization
DFC	Deferred financing costs
DOE/FECM	U.S. Department of Energy, Office of Fossil Energy and Carbon Management
EPC	Engineering, procurement, and construction
FASB	Financial Accounting Standards Board
FEED	Front-End Engineering and Design
FERC	U.S. Federal Energy Regulatory Commission
FID	Final investment decision as it pertains to the Driftwood Project
FTA countries	Countries with which the U.S. has a free trade agreement providing for national treatment for trade in natural gas
GAAP	Generally accepted accounting principles in the U.S.
Henry Hub	A common market pricing point for natural gas in the United States, located in Louisiana.
LNG	Liquefied natural gas
LSTK	Lump Sum Turnkey
Mcf	Thousand cubic feet of natural gas
MMBtu	Million British thermal unit
MMcf	Million cubic feet of natural gas
MMcf/d	MMcf per day
MMcfe	Million cubic feet of natural gas equivalent volumes using a ratio of 6 Mcf to 1 barrel of liquid
Mtpa	Million tonnes per annum
NGA	Natural Gas Act of 1938, as amended
Non-FTA countries	Countries with which the U.S. does not have a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
NYMEX	New York Mercantile Exchange
NYSE American	NYSE American LLC
Oil	Crude oil and condensate
Phase 1	Plants one and two of the Driftwood terminal
PUD	Proved undeveloped reserves
SEC	U.S. Securities and Exchange Commission
SPA	Sale and purchase agreement
Train	An industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
U.K.	United Kingdom
U.S.	United States
USACE	U.S. Army Corps of Engineers

With respect to the information relating to our ownership in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

ITEM 1 AND 2. OUR BUSINESS AND PROPERTIES

Overview

Tellurian Inc. (“Tellurian,” “we,” “us,” “our,” or the “Company”), a Delaware corporation, is a Houston-based company that is developing and plans to own and operate a portfolio of LNG marketing and infrastructure assets that includes an LNG terminal facility (the “Driftwood terminal”) and related pipelines. The Driftwood terminal and related pipelines are collectively referred to as the “Driftwood Project.” We also own upstream natural gas assets; on February 6, 2024, we announced that we are exploring a sale of those assets. We refer to the Driftwood Project and our upstream assets as the “Business.” As of December 31, 2023, our upstream natural gas assets consist of 30,034 net acres and interests in 161 producing wells located in the Haynesville Shale trend of northern Louisiana. Our Business may be developed in phases.

As part of our execution strategy, which includes increasing our asset base, we will consider various commercial arrangements with third parties across the natural gas value chain. We are also pursuing activities such as direct sales of LNG to global counterparties. We remain focused on the financing and construction of the Driftwood Project.

We manage and report our operations in three reportable segments. The Upstream segment is organized and operates to produce, gather, and deliver natural gas and to acquire and develop natural gas assets. The Midstream segment is organized to develop, construct and operate LNG terminals and pipelines. The Marketing & Trading segment is organized and operates to purchase and sell natural gas produced primarily by the Upstream segment, market the Driftwood terminal’s LNG production capacity and trade LNG.

We continue to evaluate the scope and other aspects of our Business in light of the evolving economic environment, dynamics of the global political landscape, needs of potential counterparties and other factors. How we execute our Business will be based on a variety of factors, including the results of our continuing analysis, changing business conditions and market feedback.

Overview of Significant Events

Driftwood Project Activities

During 2023, we took significant steps to advance construction of the Driftwood terminal making progress on pilings and concrete foundations. We also secured the FERC certificate for certain pipelines and continued to advance the fabrication of long-lead items.

Debt Reductions

During the first quarter of 2023, we repaid a total of approximately \$166.7 million in principal balance of our borrowing obligations.

Debt Refinancing

On August 15, 2023, we issued and sold \$250.0 million aggregate principal amount of 10% Senior Secured Notes due October 1, 2025 (the “Senior Notes”) and approximately \$83.3 million aggregate principal amount of 6% Secured Convertible Notes (the “Convertible Notes”) due October 1, 2025 (collectively the “Replacement Notes”). The issuance of the Replacement Notes resulted in the satisfaction and discharge of the Company’s outstanding principal repayment obligation under the \$500.0 million aggregate principal amount of 6.00% Senior Secured Convertible Notes (the “Extinguished Convertible Notes”).

Upstream Natural Gas Drilling Activities

During the year ended December 31, 2023, we put in production five operated Haynesville wells and participated in nine non-operated Haynesville wells that were put in production.

Natural Gas Properties

Reserves

Our natural gas assets consist of 30,034 net acres and interests in 161 producing wells located in the Haynesville Shale trend of north Louisiana. For the year ended December 31, 2023, our average net production was approximately 198.6 MMcf/d. All of our proved reserves were associated with those properties as of December 31, 2023. Proved reserves are the estimated quantities of natural gas and condensate which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., costs as of the date the estimate is made). Proved reserves are categorized as either developed or undeveloped.

Our reserves as of December 31, 2023 were estimated by Netherland, Sewell & Associates, Inc. (“NSAI”), an independent petroleum engineering firm, and are set forth in the following table. Per SEC rules, NSAI based its estimates on the 12-month unweighted arithmetic average of the first-day-of-the-month price of natural gas for each month from January through December 2023. Prices include consideration of changes in existing prices provided for under contractual arrangements, but not on escalations or reductions based upon future conditions. The price used for the reserve estimates as of December 31, 2023 was \$2.64 per MMBtu of natural gas, adjusted for energy content, transportation fees and market differentials.

The following table shows our proved reserves as of December 31, 2023:

	Natural Gas (MMcf)
Proved reserves (as of December 31, 2023):	
Developed	178,036
Undeveloped	—
Total proved reserves	<u>178,036</u>

As of December 31, 2023, the standardized measure of discounted future net cash flow from our proved reserves (the “standardized measure”) was approximately \$125.4 million.

During the year ended December 31, 2023, the Company spent approximately \$45.4 million on the conversion of our proved undeveloped reserves to proved developed reserves. The Company converted approximately 41 Bcfe of proved undeveloped to proved developed reserves, which represents a conversion rate of approximately 18%.

Refer to Supplemental Disclosures About Natural Gas Producing Activities, starting on page 71, for additional details.

Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used

Our December 31, 2023 reserve report was prepared by NSAI in accordance with guidelines established by the SEC. Reserve definitions comply with the definitions provided by Regulation S-X of the SEC. NSAI prepared the reserve report based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information we provided to them. This information was reviewed by knowledgeable members of our Company for accuracy and completeness prior to submission to NSAI. A letter that identifies the professional qualifications of the individual at NSAI who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2023, has been filed as an addendum to Exhibit 99.1 to this report and is incorporated by reference herein.

Internally, a Senior Vice President is responsible for overseeing our reserves process. Our Senior Vice President has over 20 years of experience in the oil and natural gas industry, with the majority of that time in reservoir engineering and asset management. She is a graduate of Virginia Polytechnic Institute and State University with dual degrees in Chemical Engineering and French, and a graduate of the University of Houston with a Masters of Business Administration degree. During her career, she has had multiple responsibilities in technical and leadership roles, including reservoir engineering and reserves management, production engineering, planning, and asset management for multiple U.S. onshore and international projects. She is also a licensed Professional Engineer in the State of Texas.

Production

For the years ended December 31, 2023, 2022 and 2021, we produced 72,477 MMcf, 47,322 MMcf and 14,302 MMcf of natural gas at an average sales price of \$2.25, \$5.78 and \$3.52 per Mcf, respectively. Natural gas production and operating costs for the periods ended December 31, 2023, 2022 and 2021 were \$0.44, \$0.37 and \$0.48 per Mcfe, respectively.

Drilling Activity

The information in the table below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found, or economic value. A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development, or extension well that is not a dry well. Completion refers to installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated. The table below shows the number of net productive and dry development operated and non-operated wells drilled during the past three years.

	For the Year Ended December 31,		
	2023	2022	2021
Development wells:			
Productive	3.7	13.5	6.9
Dry	—	—	—

We had no exploratory wells drilled during any of the periods presented.

Wells

As of December 31, 2023, we owned working interests in 128 gross (49.3 net) productive natural gas wells. As of December 31, 2023, there were 10 gross (6.4 net) in process wells.

Acreage

We have 9,003 gross (7,950 net) developed leasehold acres that are held by production. Additionally, we hold 23,090 gross (22,084 net) undeveloped leasehold acres. Of the total gross and net undeveloped acreage, 18,208 gross (17,688 net) acres are not held by production, of which 2,822 gross and net acres are set to expire in 2024 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed.

Volume Commitments

The Company is subject to gas gathering commitments with unrelated companies which provide dedicated gathering capacity for a portion of the Upstream segment's Haynesville Shale future natural gas production. The gas gathering agreements may require us to make deficiency payments to the extent the Company does not meet the minimum volume commitments per the terms of each contract. We expect the minimum volume commitments to total approximately 62.4 MMBtu for 2024, 49.2 MMBtu for 2025, 28.6 MMBtu for 2026 and 9.5 MMBtu for 2027. The Company expects to fulfill this commitment primarily with existing reserves. The Company will monitor current production, anticipated future production, and future development plans to meet its future commitments. See Note 10, *Commitments and Contingencies*, for further information.

Gathering, Processing and Transportation

As part of our acquisitions of natural gas properties, we also acquired certain gathering systems that deliver the natural gas we produce into third-party gathering systems. We believe that these systems and other available midstream facilities and services in the Haynesville Shale trend are adequate for our current operations and near-term growth.

Government Regulations

Our operations are and will be subject to extensive federal, state and local statutes, rules, regulations, and laws that include, but are not limited to, the NGA, the Energy Policy Act of 2005 (“EPAct 2005”), the Oil Pollution Act, the National Environmental Policy Act (“NEPA”), the Clean Air Act (the “CAA”), the Clean Water Act (the “CWA”), the Resource Conservation and Recovery Act (“RCRA”), the Natural Gas Pipeline Safety Act of 1968, as amended and including the latest Pipeline Safety Improvement Act of 2002 (the “PSIA”), and the Coastal Zone Management Act (the “CZMA”), as amended from time to time. These statutes cover areas related to the authorization, construction and operation of LNG facilities, natural gas pipelines and natural gas producing properties, including discharges and releases to the air, land and water, and the handling, generation, storage and disposal of hazardous materials and solid and hazardous wastes. These laws are administered and enforced by governmental agencies including but not limited to FERC, the U.S. Environmental Protection Agency (the “EPA”), DOE/FECM, the U.S. Department of Transportation (“DOT”), the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), the Louisiana Department of Environmental Quality and the Louisiana Department of Natural Resources. Additionally, numerous other governmental and regulatory permits and approvals have been and will be required to build and operate our Business, including, with respect to the construction and operation of the Driftwood Project, consultations and approvals by the Advisory Council on Historic Preservation, the USACE, the U.S. Department of Commerce, the National Marine Fisheries Service, the U.S. Department of the Interior, the U.S. Fish and Wildlife Service, and the U.S. Department of Homeland Security. In addition, throughout the life of the Driftwood Project, we will be subject to regular reporting requirements to FERC, PHMSA and other federal and state regulatory agencies regarding the operation and maintenance of our facilities.

Failure to comply with applicable federal, state, and local laws, rules, and regulations could result in substantial administrative, civil and/or criminal penalties and/or failure to secure and retain necessary authorizations. Criminal and regulatory enforcement agencies such as the U.S. Department of Justice have conducted investigations and have imposed criminal and civil penalties on other companies within our industry.

We have received regulatory permits and approvals in connection with the Driftwood Project including the following:

Agency	Permit / Consultation	Approval Date (<i>Anticipated</i>)
FERC	NGA Section 3 and Section 7 Approval	April 18, 2019
	NGA Section 7 Related Pipeline Approval	April 21, 2023
DOE	NGA Section 3 Approvals	FTA countries: February 28, 2017 (3968); amended December 6, 2018 (3968-A); amended December 18, 2020 (4641).
		Non-FTA countries: May 2, 2019 (4373); amended December 10, 2020 (4373-A); amended December 18, 2020 (4641)
USACE	CWA Section 404 Rivers and Harbors Act Section 10 - LNG Terminal	May 3, 2019 May 3, 2019
	CWA Section 404 - Related Pipeline Rivers and Harbors Act Section 10 - Related Pipeline	January 31, 2023 January 31, 2023
United States Coast Guard	Letter of Intent and Preliminary Water Suitability Assessment	June 21, 2016
	Follow-On Water Suitability Assessment and Letter of Recommendation	April 25, 2017
United States Fish and Wildlife Service	Section 7 of <i>Endangered Species Act</i> Consultation	September 19, 2017; February 7, 2019
	Related Pipeline - Section 7 of Endangered Species Act Consultation	August 11, 2021; October 27, 2021; April 26, 2022; June 30, 2022
National Oceanic and Atmospheric Administration / National Marine Fisheries Service	Section 7 of the <i>Endangered Species Act</i> Consultation	February 14, 2018
	<i>Magnuson-Stevens Fishery Management and Conservation Act</i> Essential Fish Habitat Consultation	October 3, 2017
	<i>Marine Mammal Protection Act</i> Consultation	October 3, 2017
State		
Louisiana Department of Natural Resources- Coastal Management Division	Coastal Use Permit and Coastal Zone Consistency Permit, Joint Permit with the USACE	June 7, 2023 (extension)
Louisiana Department of Environmental Quality - Air Quality Division	Air Permit for LNG Terminal	November 20, 2023 (renewal)
	Air Permit for Gillis Compressor Station	July 6, 2022 (renewal)
	Air Permit for Indian Bayou Compressor Station	April 26, 2023
Louisiana State Historic Preservation Office	Section 106 Consultation	Concurrence received on June 29, 2016 Concurrence received on November 22, 2016 Concurrence received on April 13, 2017 Concurrence received on March 1, 2019 Concurrence received on July 28, 2021
	Related Pipeline - Section 106 Consultation	Concurrence received on November 15, 2021 Concurrence received on March 16, 2022 Concurrence received on July 26, 2022

Federal Energy Regulatory Commission

The design, construction and operation of natural gas liquefaction facilities and pipelines, the export of LNG and the transportation of natural gas are highly regulated activities. In order to site, construct and operate the Driftwood Project, we obtained authorizations from FERC under Section 3 and Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits as detailed in the table above. Construction of the Driftwood terminal has commenced.

In order to gain regulatory certainty with respect to certain potential commercial transactions, on November 13, 2020, the Company's subsidiaries Driftwood Holdings LLC ("Driftwood Holdings") and Driftwood LNG LLC ("Driftwood LNG") (collectively, "Driftwood") filed a Petition with FERC requesting, among other things, a prospective limited waiver of FERC's buy/sell prohibition as well as any other prospective waivers necessary to enable Driftwood to purchase natural gas from potentially affiliated upstream suppliers that may be resold to a different affiliate under a long-term contract for export as LNG in foreign commerce. On January 19, 2021, FERC issued an order granting a prospective limited waiver of the prohibition on buy/sell arrangements for future proposed transactions in which Driftwood enters into: (1) an agreement to purchase natural gas from a potentially affiliated supplier; and (2) an agreement to sell LNG to affiliates in foreign commerce.

EPAct 2005 amended Section 3 of the NGA to establish or clarify FERC's exclusive authority to approve or deny an application for the siting, construction, expansion or operation of LNG terminals, although except as specifically provided in EPAct 2005, nothing in the statute is intended to affect otherwise applicable law related to any other federal agency's authorities or responsibilities related to LNG terminals.

In 2002, FERC concluded that it would apply light-handed regulation to the rates, terms and conditions agreed to by parties for LNG terminalling services, such that LNG terminal owners would not be required to provide open-access service at non-discriminatory rates or maintain a tariff or rate schedule on file with FERC, as distinguished from the requirements applied to FERC-regulated interstate natural gas pipelines. Although EPAct 2005 codified FERC's policy, those provisions expired on January 1, 2015. Nonetheless, we see no indication that FERC intends to modify its longstanding policy of light-handed regulation of LNG terminal operations.

A certificate of public convenience and necessity from FERC is required for the construction and operation of facilities used in interstate natural gas transportation, including pipeline facilities, in addition to other required governmental and regulatory approvals. In this regard, in April 2019, Driftwood Pipeline LLC ("Driftwood Pipeline") obtained a certificate of public convenience and necessity to construct and operate a pipeline that is part of the Driftwood Project. On June 17, 2021, Driftwood Pipeline filed an application pursuant to Section 7(c) of the NGA in FERC Docket No. CP21-465-000, which, as amended, requested that FERC grant a certificate of public convenience and necessity and related approvals to construct, own and operate dual 42-inch diameter natural gas pipelines, an approximately 211,200 horsepower compressor station and appurtenant facilities to be located in Beauregard and Calcasieu Parishes, Louisiana, which would provide a maximum seasonal capacity of 5.7 Bcf of natural gas per day. ("Line 200 and Line 300 Project"). On April 21, 2023, as corrected by the agency on May 2, 2023, FERC granted the application and issued a certificate of public convenience and necessity to construct and operate the Line 200 and Line 300 Project. Intervenors to the proceeding (Healthy Gulf and Sierra Club) filed a request for rehearing of FERC's order issuing the certificate, which FERC denied by operation of law on June 22, 2023.

On August 21, 2023, Healthy Gulf and Sierra Club petitioned for review in the United States Court of Appeals for the District of Columbia Circuit of the April 21, 2023 FERC order. Driftwood LNG and Driftwood Pipeline moved to intervene on September 8, 2023. On October 11, 2023, the Court granted Driftwood LNG and Driftwood Pipeline's motion to intervene. Briefing is ongoing.

On October 4, 2023, Driftwood LNG and Driftwood Pipeline filed a request with FERC for an extension of time to complete construction of and place in-service one of the Driftwood pipelines and the Driftwood terminal. Driftwood LNG and Driftwood Pipeline requested that FERC grant an approximately 36-month extension of time so that it may construct and place such Driftwood Project facilities in service. On February 15, 2024, FERC granted the request; and as extended, the FERC order requires construction to be completed by April 18, 2029. When completed, the facility will have a capacity of approximately 27.6 Mtpa.

FERC's jurisdiction under the NGA generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial or any other use and to natural gas companies engaged in such transportation or sale. FERC's jurisdiction does not extend to the production, gathering, local distribution or export of natural gas.

Specifically, FERC's authority to regulate interstate natural gas pipelines includes:

- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;

- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

In addition, FERC has the authority to approve, and if necessary set, “just and reasonable rates” for the transportation or sale of natural gas in interstate commerce. Relatedly, under the NGA, our proposed pipelines will not be permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service to any shipper, including our own affiliates.

EPA 2005 amended the NGA to make it unlawful for any entity, including otherwise non-jurisdictional producers, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” natural gas sales, purchases or transportation subject to FERC jurisdiction. EPA 2005 also gives FERC authority to impose civil penalties for violations of the NGA or Natural Gas Policy Act of approximately \$1.5 million per day per violation.

On February 18, 2022, FERC issued two policy statements: (1) an updated policy statement describing how it will determine whether a new interstate natural gas transportation project is required by the public convenience and necessity under section 7 of the NGA; and (2) an interim policy statement explaining how FERC will assess the impacts of natural gas infrastructure projects on climate change in its review under the National Environmental Policy Act and the NGA. On March 24, 2022, FERC reissued the policy statements as drafts and requested additional comments. FERC is not applying the draft policy statements to new or pending applications until FERC issues the final policy statements. It is not clear when, or if, the final policy statements will be issued.

On October 23, 2023, FERC issued a final rule in Order No. 900 which revised its regulations governing engineering and design materials for LNG facilities related to potential impacts caused by natural hazards. The final rule primarily removed references to outdated technical standards and codified engineering and design information materials previously contained in a FERC guidance document regarding seismic and other natural hazards. The Commission stated in Order No. 900 that the final rule has no retroactive effect, but will apply to applications to construct new LNG facilities or recommission existing LNG facilities.

Transportation of the natural gas we produce, and the prices we pay for such transportation, will be significantly affected by the foregoing laws and regulations.

U.S. Department of Energy, Office of Fossil Energy Export Licenses

Under the NGA, exports of natural gas to FTA countries are “deemed to be consistent with the public interest,” and authorization to export LNG to FTA countries shall be granted by the DOE/FECM “without modification or delay.” FTA countries currently capable of importing LNG include but are not limited to Canada, Chile, Colombia, Jordan, Mexico, Singapore, South Korea and the Dominican Republic. Exports of natural gas to Non-FTA countries are authorized unless the DOE/FECM “finds that the proposed exportation” “will not be consistent with the public interest.” Driftwood LNG has authorization from the DOE/FECM to export LNG in a volume up to the equivalent of 1,415.3 Bcf per year of natural gas to FTA countries for a term of 30 years and to Non-FTA countries for a term through December 31, 2050.

On April 21, 2023, DOE/FECM issued a Policy Statement on Export Commencement Deadlines in Authorizations to Export Natural Gas to Non-Free Trade Agreement Countries, which changed DOE/FECM’s standard for granting extensions of time to commence LNG exports to Non-FTA countries. In the policy statement, DOE/FECM reaffirmed the seven-year deadline for authorization holders to commence exports of domestically produced natural gas, including LNG, to Non-FTA countries and provided notice that, in general, it intends to allow non-FTA authorizations to expire at the end of the seven-year period if exports have not commenced, unless the authorization holder satisfies certain requirements. Specifically, DOE/FECM will require a Non-FTA authorization holder seeking an extension to demonstrate that: (1) the authorization holder has physically commenced construction of the associated export facility prior to making the extension request; and (2) the authorization holder’s inability to meet the commencement deadline is the result of extenuating circumstances outside of the authorization holder’s control, including but not limited to acts of God. The policy statement does not apply to exports to FTA countries.

On January 26, 2024, the Biden Administration announced a temporary pause on new and pending approvals of applications to export LNG to Non-FTA countries. This pause is in effect until the DOE can update its underlying economic and environmental analyses for such authorizations. This announcement does not impact the validity of previously issued Non-

FTA authorizations or applications for FTA authorization. Moreover, the DOE has clarified that applications for extensions of the commencement date for existing Non-FTA authorizations remain unaffected by the pause.

Federal and State Regulation of Pipeline and Hazardous Materials Safety

The Natural Gas Pipeline Safety Act of 1968 (the “NGPSA”) authorizes DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases, as well as the transportation and storage of LNG. Amendments to the NGPSA include the Pipeline Safety Act of 1979, which addresses liquids pipelines, and the PSIA, which governs the areas of testing, education, training, and communication. The NGPSA, as amended, also grants the authority to impose civil penalties for pipeline safety violations up to a maximum of \$266,015 for a single violation and \$2,660,135 for a series of related violations, as well as a maximum additional penalty for each LNG pipeline facility violation of \$97,179.

PHMSA administers pipeline safety regulations for jurisdictional gas gathering, transmission, and distribution systems under minimum federal safety standards. PHMSA also establishes and enforces safety regulations for onshore LNG facilities, which are defined as pipeline facilities used for the transportation or storage of LNG subject to such safety standards. Those regulations address requirements for siting, design, construction, equipment, operations, personnel qualification and training, fire protection, and security of LNG facilities. The Driftwood terminal will be subject to such PHMSA regulations.

The pipelines comprising part of the Driftwood Project will also be subject to regulation by PHMSA, including those under the PSIA. The PHMSA Office of Pipeline Safety administers the PSIA, which requires pipeline companies to perform extensive integrity tests on natural gas transportation pipelines that exist in high population density areas designated as “high consequence areas.” Pipeline companies are required to perform the integrity tests on a seven-year cycle. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. Pipeline operators also must develop integrity management programs for natural gas transportation pipelines, which requires pipeline operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline, as necessary; and implement preventive and mitigative actions.

On December 27, 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) of 2020 was signed into law as part of the Consolidated Appropriations Act of 2021. The legislation reauthorizes the PHMSA pipeline safety program through fiscal year 2023 and provides for advances to improve pipeline safety. The legislation includes a directive to PHMSA to update its current regulations for large-scale LNG facilities.

On January 11, 2021, PHMSA published a final rule in the Federal Register amending the Federal Pipeline Safety Regulations to reduce regulatory burdens and offer greater flexibility with respect to the construction, maintenance, and operation of gas transmission, distribution, and gathering pipeline systems, including updates to corrosion control requirements and test requirements for pressure vessels. Mandatory compliance with this rule started on October 1, 2021.

On November 15, 2021, PHMSA published a final rule in the Federal Register revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas gathering pipelines. The rule extends reporting requirements to all gas gathering operators and applies a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. This rule went into effect on May 16, 2022.

On April 8, 2022, as subsequently corrected on August 1, 2023, PHMSA published a final rule in the Federal Register revising the Federal Pipeline Safety Regulations applicable to most newly constructed and entirely replaced onshore gas transmission, certain gas gathering, and hazardous liquid pipelines with diameters of six inches or greater. In the revised regulations, PHMSA establishes requirements for operators of these lines to install rupture-mitigation valves or alternative equivalent technologies and establishes minimum performance standards for those valves and requirements for rupture-mitigation valve spacing, maintenance and inspection, and risk analysis, among other actions. The final rule went into effect on October 5, 2022, with the corrections to the final rule effective as of August 1, 2023.

On August 24, 2022, as subsequently corrected on October 25, 2022 and April 24, 2023, PHMSA published a final rule in the Federal Register revising the Federal Pipeline Safety Regulations relating to improved safety of onshore gas transmission pipelines. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the amendments. The final rule went into effect on May 24, 2023.

The pipelines comprising part of the Driftwood Project will be subject to regulation by PHMSA, which will involve capital and operating costs for compliance-related equipment and operations. We have no reason to believe that these compliance costs will be material to our financial performance, but the significance of such costs will depend on future events and our ability to achieve and maintain compliance throughout the life of the Driftwood Project or related pipelines.

Natural Gas Pipeline Safety Act of 1968

The State of Louisiana also administers certain federal pipeline safety standards under the NGPSA, which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal sanctions.

Other Governmental Permits, Approvals and Authorizations

The construction and operation of the Driftwood Project are subject to federal permits, approvals and consultations required by other federal and state agencies, including DOT, the Advisory Council on Historic Preservation, the USACE, the U.S. Department of Commerce, the National Marine Fisheries Service, the U.S. Department of the Interior, the U.S. Fish and Wildlife Service, the EPA and the U.S. Department of Homeland Security. The necessary permits and approvals required for construction have been obtained and will be required to be maintained for the Driftwood Project. Failure to comply with applicable permits, approvals and authorizations could result in substantial administrative, civil and/or criminal penalties and/or failure to retain such permits, approvals and authorizations.

Three significant permits that apply to the Driftwood Project are the USACE Section 404 of the CWA/Section 10 of the Rivers and Harbors Act Permit, the CAA Title V Operating Permit and the Prevention of Significant Deterioration Permit, of which the latter two permits are issued by the Louisiana Department of Environmental Quality. Each of the Driftwood terminal and related pipelines has received its permit from the USACE, including a review and approval by the USACE of the findings and conditions set forth in an Environmental Impact Statement and Record of Decision issued for the Driftwood terminal and [the related pipelines] pursuant to the requirements of NEPA. The Louisiana Department of Environmental Quality has issued the Prevention of Significant Deterioration permit, which is required to commence construction of the Driftwood terminal, as well as the Title V Operating Permit.

Environmental Regulation

Our operations are and will be subject to various federal, state and local laws and regulations relating to the protection of the environment and natural resources, the handling, generation, storage and disposal of hazardous materials and solid and hazardous wastes and other matters. These environmental laws and regulations, which can restrict or prohibit impacts to the environment or the types, quantities and concentration of substances that can be released into the environment, will require significant expenditures for compliance, can affect the cost and output of operations, may impose substantial administrative, civil and/or criminal penalties for non-compliance and can result in substantial liabilities. These laws and regulations may be modified or amended in the future, which may impose material costs or require operational limitations or changes.

The Biden Administration has issued a number of executive orders that direct federal agencies to take actions that may change regulations and guidance applicable to our business.

For example, Executive Order 14008, “Tackling the Climate Crisis at Home and Abroad,” 86 FR 7619 (January 27, 2021), establishes a policy “promoting the flow of capital toward climate-aligned investments and away from high-carbon investments.” It also requires the heads of agencies to identify any fossil fuel subsidies provided by their respective agencies, and to seek to eliminate fossil fuel subsidies from the budget request for fiscal year 2022 and thereafter.

Executive Order 13990, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” 86 FR 7037 (January 20, 2021) directs agencies to review regulations and policies adopted by the Trump Administration and to “confront the climate crisis.” It specifically directs the EPA to consider suspending, revising or rescinding certain regulations, including restrictions on emissions from the oil and gas sector. In addition, Executive Order 13990 establishes a federal inter-agency working group to recommend methods for agencies to incorporate the “social cost of carbon” into their decision-making. In addition, Executive Order 13990 directs the White House Council on Environmental Quality to rescind draft guidance restricting the review of climate change issues in reviews under NEPA and to update regulations to strengthen climate change reviews. In November 2022, the EPA requested public comment on a technical report on the social cost of greenhouse gases and announced that it was also conducting an external peer review of the report, which estimates a substantially higher social carbon cost than past EPA estimates. On February 9, 2023, the peer review panel was selected to review this technical report and final comments on the report were published on May 4, 2023. The EPA stated that it is taking the peer review recommendations under advisement.

NEPA. NEPA and comparable state laws and regulations require that government agencies review the environmental impacts of proposed projects. On January 9, 2023, the CEQ published interim guidance for federal agencies on the

consideration of greenhouse gas (“GHG”) emissions and climate change under NEPA. On June 3, 2023, President Biden signed the Fiscal Responsibility Act of 2023, which amended NEPA with a goal of streamlining the NEPA process. On July 31, 2023, CEQ published proposed NEPA regulations to implement NEPA amendments that were part of the Fiscal Responsibility Act, to revise prior NEPA regulations, and improve efficiency and effectiveness of the environmental review process. The impact on us of these and future developments in NEPA regulation and guidance is not determinable at this time, especially with respect to those aspects of our operations and development projects that may require future federal approvals.

Clean Air Act. The CAA and comparable state laws and regulations restrict the emission of air pollutants from regulated sources and impose various monitoring and reporting requirements, among other requirements. The Driftwood Project includes facilities and operations that are subject to the federal CAA and comparable state and local laws, including requirements to obtain pre-construction permits and operating permits. We may be required to incur capital expenditures for air pollution control equipment in connection with maintaining or obtaining permits and approvals pursuant to the CAA and comparable state laws and regulations.

On December 2, 2023, the EPA announced a final rule to reduce emissions of methane and volatile organic compounds from oil and natural gas operations. The rule establishes separate requirements for new and existing sources. For new sources, the rule phases in restrictions on routine flaring from oil wells and includes provisions for leak detection and repair, storage vessels, pneumatic controllers, and pumps. For existing sources, the EPA issued emissions guidelines for states to follow in regulating methane emissions from oil and gas operations. State plans may incorporate similar standards to the federal requirements or states may develop their own standards that are as strict as the federal requirements. The impact of the final rule on our operations and any related costs and obligations will depend on the specific state plans adopted and is not yet fully determinable.

Following the publication of proposed revisions on January 27, 2023 to the primary (health-based) annual PM_{2.5} standard, the EPA finalized the rule on February 7, 2024. The finalized EPA rule strengthens the health-based annual PM_{2.5} standard from the previously proposed range, setting it at 9.0 µg/m³. Furthermore, the finalized rule modifies the PM_{2.5} monitoring network design criteria to include a factor that accounts for the proximity of populations at increased risk of PM_{2.5}-related health effects to sources of air pollution. The Driftwood Project and related pipelines are in compliance with existing permits. We will continue to be mindful of this updated standard and its potential influence on our future operational and environmental strategies, including any potential project modifications or operational changes.

In addition, under the Biden Administration, the EPA has released guidance documents intended to assist in the evaluation of environmental justice considerations in many aspects of governmental decision making. Among other things, the guidance emphasizes a focus on advancing environmental justice goals in connection with federal permitting and regulatory programs like the Clean Air Act. The impact of this guidance on us is not determinable at this time.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment because emissions of GHGs are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings provide the basis for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In June 2010, the EPA began regulating GHG emissions from stationary sources, including LNG terminals.

As discussed above, the Biden Administration has issued Executive Orders with respect to certain governmental actions related to climate change, and the EPA has promulgated, and may promulgate additional, regulations for sources of GHG emissions that could affect the oil and gas sector, and Congress or states may enact new GHG legislation, any of which could impose emission limits on the Driftwood Project or related pipelines or require us to implement additional pollution control technologies, pay fees related to GHG emissions or implement mitigation measures. On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 (“IRA”). The IRA imposes a fee of up to \$1,500 per metric ton of methane emitted above specified thresholds from onshore petroleum and natural gas production facilities, natural gas processing facilities, natural gas transmission and compression facilities, and onshore petroleum and natural gas gathering and boosting facilities, among other facilities. On January 26, 2024, the EPA published a proposed rule to implement the IRA’s mandated fees on methane emissions. The proposal outlines formulas for calculating taxable emissions, defines exemptions, and sets forth reporting and payment procedures. It also establishes penalties for non-payment. The rule is open for public comment until March 11, 2024. The first tax payments will be due by March 31, 2025, for emissions during calendar year 2024. The scope and effects of the final rule are difficult to predict at this time. Once finalized, the Company will assess the potential impacts on the Driftwood Project and related pipelines as implementation plans are developed.

Coastal Zone Management Act. Certain aspects of the Driftwood terminal are subject to the requirements of the CZMA. The CZMA is administered by the states (in Louisiana, by the Department of Natural Resources). This program is implemented to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas. Certain facilities that are part of the Driftwood Project obtained permits for construction and operation in coastal areas pursuant to the requirements of the CZMA.

Clean Water Act. The Driftwood Project is subject to the CWA and analogous state and local laws. The CWA and analogous state and local laws regulate discharges of pollutants to waters of the United States or waters of the state, including discharges of wastewater and storm water runoff and discharges of dredged or fill material into waters of the United States, as well as spill prevention, control and countermeasure requirements. Permits must be obtained prior to discharging pollutants into state and federal waters or dredging or filling wetland and coastal areas. The CWA is administered by the EPA, the USACE and in the state of Louisiana, the Louisiana Department of Environmental Quality. Additionally, the siting and construction of the Driftwood Project will impact jurisdictional wetlands, which would require appropriate federal, state and/or local permits and approval prior to impacting such wetlands. The authorizing agency may impose significant direct or indirect mitigation costs to compensate for regulated impacts to jurisdictional wetlands. Although the CWA permits required for construction and operation of the Driftwood Project have been obtained, other CWA permits may be required in connection with our projects that are under development and our future projects. The approval timeframe could potentially affect project schedules.

In addition, in recent years, certain CWA regulatory programs, including the Section 404 wetlands permitting program, have been the subject of shifting legal interpretations, including in a case, *Sackett v. EPA*. On May 25, 2023, the Supreme Court issued an opinion in *Sackett v. EPA* that narrowed the scope of “waters of the United States” under the CWA. The Court ruled that jurisdiction under the CWA only extends to wetlands that have continuous surface connection with relatively permanent bodies of water connected to traditional interstate navigable waters. On September 8, 2023, the EPA and the Department of the Army published a final rule to conform the prior regulatory definition of “waters of the United States” with the Supreme Court decision in *Sackett v. EPA*. Further regulatory changes or judicial decisions in this area could affect the Driftwood Project in ways that cannot be predicted at this time.

On July 19, 2022, Healthy Gulf and Sierra Club petitioned for review, in the United States Court of Appeals for the Fifth Circuit, of the Army Corps of Engineers Permit, MVN-2016-01501-WII, issued to Driftwood LNG and Driftwood Pipeline on May 3, 2019 under section 404 of the CWA. Petitioners alleged Administrative Procedure Act and CWA violations. On August 4, 2022, Driftwood LNG and Driftwood Pipeline moved to intervene. On September 6, 2023, the Court denied the petition in its entirety.

Federal laws, including the CWA, require certain owners or operators of facilities that store or otherwise handle oil and produced water to prepare and implement spill prevention, control, and countermeasure plans addressing the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 (“OPA”) subjects owners and operators of facilities to strict and joint and several liability for all containment and cleanup costs and certain other damages arising from oil spills, including the government’s response costs. Spills subject to the OPA may result in varying civil and criminal penalties and liabilities. Although the Driftwood Project incorporates appropriate equipment and operational measures to reduce the potential for spills of oil and establish protocols for responding to spills, oil spills remain an operational risk that could adversely affect our operations and result in additional costs or fines or penalties.

Resource Conservation and Recovery Act. The federal RCRA and comparable state requirements govern the generation, handling and disposal of solid and hazardous wastes and require corrective action for releases of such wastes into the environment. In the event such wastes are generated or used in connection with our facilities, we will be subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes and could be required to perform corrective action measures to clean up releases of such wastes.

Wastes from oil and gas activities are currently excluded from certain regulatory programs under RCRA. In response to litigation by environmental groups over the EPA’s alleged failure to periodically review existing RCRA regulations, the EPA and certain environmental groups entered into a consent decree pursuant to which the EPA was required to undertake a review of whether changes to the existing regulations were necessary. In April 2019, the EPA issued a report concluding that such revisions were unnecessary. A loss of the exclusion from RCRA coverage for oil and gas-related wastes, including drilling fluids, produced waters and related wastes in the future, could result in a significant increase in our costs to manage and dispose of waste associated with our production operations.

The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”). CERCLA, often referred to as Superfund, and comparable state statutes, impose liability that is generally joint and several and that is retroactive for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, for the release of a “hazardous substance” (or under state law, other specified substances) into the environment. So-called potentially responsible parties (“PRPs”) include the current and certain past owners and operators of a facility where there has been a release or threat of release of a hazardous substance and persons who disposed of or arranged for the disposal of, or transported hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties and/or from conditions at disposal facilities where materials were sent. Our operations involve the use or handling of materials that include or may be classified as hazardous substances under CERCLA or regulated under similar state statutes. We may also be the owner or operator of sites on which hazardous

substances have been released and may be responsible for the investigation, management and disposal of soils or dredge spoils containing hazardous substances in connection with our operations.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at some of our properties by previous owners and operators. Materials from these operations remain on some of the properties and, in certain instances, may require remediation. In some instances, we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. Accordingly, we could incur material costs for remediation required under CERCLA or similar state statutes in the future.

Hydraulic Fracturing. Hydraulic fracturing is commonly used to stimulate the production of crude oil and/or natural gas from dense subsurface rock formations. We plan to use hydraulic fracturing extensively in our natural gas development operations. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the natural gas to more easily flow to the wellbore. The process is generally subject to regulation by state oil and natural gas commissions but is also subject to new and changing regulatory programs at the federal, state and local levels.

In February 2014, the EPA issued permitting guidance under the Safe Drinking Water Act (“SDWA”) for the underground injection of liquids from hydraulically fractured wells and other wells where diesel is used. Depending upon how it is implemented, this guidance may create duplicative requirements in certain areas, further slow the permitting process in certain areas, increase the costs of operations, and result in expanded regulation of hydraulic fracturing activities related to the Driftwood Project.

In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act (“TSCA”) pursuant to which it collected extensive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. If the EPA regulates hydraulic fracturing fluid under TSCA in the future, such regulation may increase the cost of our natural gas development operations and the feedstock for the Driftwood terminal.

In June 2016, the EPA finalized pretreatment standards for indirect discharges of wastewater from the oil and natural gas extraction industry. The regulation prohibits sending wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly-owned treatment works. Certain activities of our Business are subject to the pretreatment standards, which means that we are required to use disposal methods that may require additional permits or cost more to implement than disposal at publicly-owned treatment works.

In December 2016, the EPA released a report titled “Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States.” The report concluded that activities involved in hydraulic fracturing can have impacts on drinking water under certain circumstances. In addition, the U.S. Department of Energy has investigated practices that the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. These and similar studies, depending on their degree of development and the nature of results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. If the EPA proposes additional regulations of hydraulic fracturing in the future, it could impose additional emission limits and pollution control technology requirements, which could limit our operations and revenues and potentially increase our costs of gas production or acquisition.

Endangered Species Act (“ESA”). Our operations may be restricted by requirements under the ESA. The ESA prohibits the harassment, harming or killing of certain protected species and destruction of protected habitats. Under the NEPA review process conducted by FERC, we have been and will be required to consult with federal agencies to determine limitations on and mitigation measures applicable to activities that have the potential to result in harm to threatened or endangered species of plants, animals, fish and their designated habitats. Although we have conducted studies and engaged in consultations with agencies in order to avoid harming protected species, inadvertent or incidental harm may occur in connection with the construction or operation of our properties, including the Driftwood Project or related pipelines, which could result in fines or penalties. In addition, if threatened or endangered species are found on any part of our properties, including the sites of the Driftwood Project, or pipeline rights of way, then we may be required to implement avoidance or mitigation measures that could limit our operations or impose additional costs.

Regulation of Natural Gas Operations

Our natural gas operations are subject to a number of additional laws, rules and regulations that require, among other things, permits for the drilling of wells, drilling bonds and reports concerning operations. States, parishes and municipalities in which we operate may regulate, among other things:

- the location of new wells;
- the method of drilling, completing and operating wells;

- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- notice to surface owners and other third parties; and
- produced water and waste disposal.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states, including Louisiana, allow forced pooling or integration of tracts to facilitate exploration, while other states rely on the voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells and generally prohibit the venting or flaring of natural gas and require that oil and natural gas be produced in a prorated, equitable system. These laws and regulations may limit the amount of oil and natural gas that we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, most states, and some local authorities, impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas and minerals in place within their jurisdictions. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

Anti-Corruption, Trade Control, and Tax Evasion Laws

We are subject to anti-corruption laws in various jurisdictions that prohibit bribery and corruption, such as the U.S. Foreign Corrupt Practices Act of 1977, as amended (the “FCPA”), the U.K. Bribery Act 2010 and other anti-corruption laws. The FCPA and these other laws generally prohibit our employees, directors, officers and agents from authorizing, offering, or providing improper payments or anything else of value to government officials or other covered persons to obtain or retain business or gain an improper business advantage. We are also subject to laws that prohibit commercial bribery. We face the risk that one of our employees or agents will offer, authorize, or provide something of value that could subject us to liability under the FCPA and other anti-corruption laws. In addition, we cannot predict the nature, scope or effect of future regulatory requirements to which our international operations might be subject or the manner in which existing laws might be administered or interpreted.

We are also subject to other laws and regulations governing our international operations, including regulations administered by the U.S. Department of Commerce’s Bureau of Industry and Security, the U.S. Department of Treasury’s Office of Foreign Assets Control, the U.K. Office of Financial Sanctions Implementation, and various international government entities, including applicable export control regulations, economic sanctions on countries and persons, customs requirements, currency exchange regulations, and transfer pricing regulations (collectively, “Trade Control laws”).

We are also subject to U.K. corporate criminal offenses for failure to prevent the facilitation of tax evasion pursuant to the Criminal Finances Act 2017, which imposes criminal liability on a company where it has failed to prevent the criminal facilitation of tax evasion by a person associated with the company.

We have instituted policies, procedures and ongoing training of employees designed to ensure that we and our employees and agents comply with the FCPA, other anti-corruption laws, Trade Control laws and the Criminal Finances Act 2017. However, there is no assurance that our efforts have been and will be completely effective in ensuring our compliance with all applicable anti-corruption laws, including the FCPA, other anti-corruption laws, Trade Control laws, the Criminal Finances Act 2017 or other legal requirements. If we are not in compliance with the FCPA, other anti-corruption laws, Trade Control laws or the Criminal Finances Act 2017, we may be subject to criminal and civil penalties, disgorgement and other sanctions and remedial measures, and legal expenses, which could have a material adverse impact on our business, financial condition, results of operations and liquidity. Likewise, any investigation of any potential violations of the FCPA, other anti-corruption laws, the Trade Control laws or the Criminal Finances Act 2017 by the U.S. or foreign authorities could have a material adverse impact on our reputation, business, financial condition and results of operations. U.S. or foreign authorities may also seek to hold us liable for successor liability for anti-corruption or Trade Control law violations, or violations of the Criminal Finances Act 2017, committed by companies we acquire or in which we invest (for example, by way of acquiring equity interests, participating as a joint venture partner, or acquiring assets).

Competition

We are subject to a high degree of competition in all aspects of our business. See “Item 1A — Risk Factors — Risks Relating to Our Business in General — *Competition is intense in the energy industry and some of Tellurian’s competitors have greater financial, technological and other resources.*”

Production & Transportation. The natural gas and oil business is highly competitive in the exploration for and acquisition of reserves, the acquisition of natural gas and oil leases, equipment and personnel required to develop and produce reserves, and the gathering, transportation and marketing of natural gas and oil. Our competitors include national oil companies,

major integrated natural gas and oil companies, other independent natural gas and oil companies, and participants in other industries supplying energy and fuel to industrial, commercial, and individual consumers, such as operators of pipelines and other midstream facilities. Many of our competitors have longer operating histories, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we currently possess.

Liquefaction. The Driftwood terminal will compete with liquefaction facilities worldwide to supply low-cost liquefaction to the market. There are a number of liquefaction facilities worldwide that we compete with for customers. Many of the companies with which we compete have greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we do.

LNG Marketing. Tellurian competes with a variety of companies in the global LNG market, including (i) integrated energy companies that market LNG from their own liquefaction facilities, (ii) trading houses and aggregators with LNG supply portfolios, and (iii) liquefaction plant operators that market equity volumes. Many of the companies with which we compete have greater name recognition, larger staffs, greater access to the LNG market and substantially greater financial, technical, and marketing resources than we do.

Title to Properties

With respect to our natural gas producing properties, we believe that we hold good and defensible leasehold title to substantially all of our properties in accordance with standards generally accepted in the industry. A preliminary title examination is conducted at the time the properties are acquired. Our natural gas properties are subject to royalty, overriding royalty, and other outstanding interests. We believe that we hold good title to our other properties, subject to customary burdens, liens, or encumbrances that we do not expect to materially interfere with our use of the properties.

Major Customers

We do not have any major customers.

Facilities

Certain subsidiaries of Tellurian have entered into operating leases for office space in Houston, Texas, Washington, D.C. and London, United Kingdom. The tenors of the leases are approximately five, ten and five years for Houston, Washington, D.C. and London, respectively.

Employees and Human Capital

As of December 31, 2023, Tellurian had 168 full-time employees worldwide. None of them are subject to collective bargaining arrangements. The Company's workforce is primarily located in Houston, Texas, and we have offices in Louisiana, Washington DC, London and Singapore. Many of our employees are originally from or have extensive experience working in countries other than the United States. This reflects our overall strategy of building a natural gas business that is global in scope.

We plan to build, among other things, an LNG liquefaction facility that we believe is one of the largest energy infrastructure projects currently under development in the United States. Given the inherent challenges involved in the construction of a project of this type, in particular by a company that has limited current operations, our human resources strategy focuses on the recruitment and retention of employees who have already established relevant expertise in the industry. The execution of this strategy has resulted in us assembling what we believe to be a premier management team in the global natural gas and LNG industry. A related aspect of our human resources strategy is that the compensation structure for many of our employees is weighted towards incentive compensation that is designed to reward progress toward the development of our business, including in particular the financing and construction of the Driftwood Project.

Jurisdiction and Year of Formation

The Company is a Delaware corporation originally formed in 1967 and formerly known as Magellan Petroleum Corporation.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available free of charge from the SEC's website at www.sec.gov or from our website at www.tellurianinc.com. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact Tellurian Inc., Investor Relations, 1201 Louisiana Street, Suite 3100, Houston, Texas 77002.

ITEM 1A. RISK FACTORS

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments. Our risk factors are grouped into the following categories:

- Risks Relating to Financial Matters;
- Risks Relating to Our Common Stock;
- Risks Relating to Our LNG Business;
- Risks Relating to Our Natural Gas and Oil Operating Activities; and
- Risks Relating to Our Business in General.

Risks Relating to Financial Matters

There is substantial doubt about our ability to continue as a going concern.

To date, we have been meeting our liquidity needs primarily from cash on hand and the combined proceeds generated by debt and equity issuances, upstream operations, and the sale of common stock under our at-the-market equity offering programs. As of December 31, 2023, we had approximately \$75.8 million in cash and cash equivalents, which we expect will not be sufficient to satisfy our obligations and fund our working capital needs for the next twelve months. There is substantial doubt about our ability to continue as a going concern.

We continue to evaluate ways to generate additional proceeds from potential financing transactions, including but not limited to the potential sale of our upstream natural gas assets, issuances of equity, equity-linked and debt securities, or similar transactions, managing certain operating and overhead costs, amending or refinancing the Replacement Notes and offering equity interests in the Driftwood Project (collectively “Management’s Plans”), to fund our obligations and working capital needs. Our ability to effectively implement Management’s Plans is subject to numerous risks and uncertainties such as a potential inability to sell our upstream assets, market demand for our equity and debt securities, commodity prices, and other factors affecting natural gas markets. As such, there can be no assurance that we will be able to implement Management’s Plans or otherwise obtain additional liquidity or refinance existing indebtedness on acceptable terms or at all.

Tellurian will be required to seek additional equity and/or debt financing in the future to complete the Driftwood Project and to grow its other operations, and may not be able to secure such financing on acceptable terms, or at all.

Tellurian will be unable to generate any significant revenue from the Driftwood Project for multiple years, and expects cash flow from its other lines of business to be modest for an extended period as it focuses on the development and growth of these businesses. Tellurian will, therefore, need substantial amounts of additional financing to execute its business plan and to repay its indebtedness when necessary. There can be no assurance that Tellurian will be able to raise sufficient capital on acceptable terms, or at all. Tellurian’s ability to raise financing, and the terms of that financing, will depend to a significant extent on factors outside of its control such as global market conditions. Interest rates rose significantly in 2022 and 2023 in response to inflationary pressures in the U.S. and world economies, and rising interest rates generally make financing more difficult to obtain as well as more expensive. If adequate financing is not available on satisfactory terms or at all, Tellurian may be required to delay, scale back or cancel the development of business opportunities, and this could adversely affect its operations and financial condition to a significant extent. Tellurian intends to pursue a variety of potential financing transactions, including project finance transactions and sales of equity and debt securities. We do not know whether, and to what extent, potential sources of financing will find the terms we propose acceptable. In addition, potential sources of financing may conclude that the terms of our commercial agreements for the sale of LNG are not attractive enough to justify an investment.

Debt or preferred equity financing, if obtained, may involve agreements that include liens or restrictions on Tellurian’s assets and covenants limiting or restricting our ability to take specific actions, such as paying dividends or making distributions, incurring additional debt, acquiring or disposing of assets and increasing expenses. Debt financing would also be required to be repaid regardless of Tellurian’s operating results. Obtaining financing through additional issuances of common stock or other equity securities would impose fewer restrictions on our future operations but would be dilutive to the interests of existing stockholders. If we are unable to sell our Upstream assets for an acceptable price, this would further limit our financing options.

We have a limited operating history and expect to incur losses for a significant period of time.

We have a limited operating history. Although Tellurian’s current directors, managers and officers have prior professional and industry experience, our business is in an early stage of development. Accordingly, the prior history, track record and historical financial information you may use to evaluate our prospects are limited.

Completion of construction of the Driftwood Project will require Tellurian to incur costs and expenses much greater than those it has incurred to date. The Company also expects to devote substantial amounts of capital to the growth and

development of its other operations. Tellurian expects to continue to incur operating losses and negative operating cash flows for an extended period.

Tellurian's exposure to the performance and credit risks of its counterparties may adversely affect its operating results, liquidity and access to financing.

Our operations involve our entering into various construction, purchase and sale, hedging, supply and other transactions with numerous third parties. In such arrangements, we will be exposed to the performance and credit risks of our counterparties, including the risk that one or more counterparties fail to perform their obligations under the applicable agreement. Some of these risks may increase during periods of commodity price volatility. In some cases, we will be dependent on a single counterparty or a small group of counterparties, all of whom may be similarly affected by changes in economic and other conditions. These risks include, but are not limited to, risks related to the construction of the Driftwood terminal discussed below in “— Risks Relating to Our LNG Business — *Tellurian will be dependent on third-party contractors for the successful completion of the Driftwood terminal, and these contractors may be unable to complete the Driftwood terminal.*” Defaults by suppliers and other counterparties may adversely affect our operating results, liquidity and access to financing.

Our use of hedging arrangements may adversely affect our future operating results or liquidity.

As we continue to develop our LNG and natural gas marketing and natural gas operating activities, we may enter into commodity hedging arrangements in an effort to reduce our exposure to fluctuations in price and timing risk. Any hedging arrangements entered into would expose us to the risk of financial loss when (i) the counterparty to the hedging contract defaults on its contractual obligations or (ii) there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received.

Also, commodity derivative arrangements may limit the benefit we would otherwise receive from a favorable change in the relevant commodity price. In addition, regulations issued by the Commodities Futures Trading Commission, the SEC and other federal agencies establishing regulation of the over-the-counter derivatives market could adversely affect our ability to manage our price risks associated with our LNG and natural gas activity and therefore have a negative impact on our operating results and cash flows.

Changes in tax laws or exposure to additional income tax liabilities could have a material impact on our financial condition, results of operations and liquidity.

Factors that could materially affect our future effective tax rates include but are not limited to:

- changes in the regulatory environment;
- changes in accounting and tax standards or practices;
- changes in U.S., state or foreign tax laws;
- changes in the composition of operating income by tax jurisdiction; and
- our operating results before taxes.

We are also subject to examination by the Internal Revenue Service (the “IRS”) and other tax authorities, including state revenue agencies and other foreign governments. While we regularly assess the likelihood of favorable or unfavorable outcomes resulting from examinations by the IRS and other tax authorities to determine the adequacy of our provision for income taxes, there can be no assurance that the outcome resulting from these examinations will not materially adversely affect our financial condition and operating results. Additionally, the IRS and several foreign tax authorities have increasingly focused attention on intercompany transfer pricing with respect to sales of products and services and the use of intangibles. Tax authorities could disagree with our cross-jurisdictional transfer pricing or other matters and assess additional taxes. If we do not prevail in any such disagreements, our profitability may be affected.

Tellurian does not expect to generate sufficient cash to pay dividends until the completion of construction of the Driftwood Project.

Tellurian’s directly and indirectly held assets currently consist primarily of natural gas leaseholds and related upstream development assets, cash held for certain development and operating expenses, applications for permits from regulatory agencies relating to the Driftwood Project and certain real property related to that project. Tellurian’s cash flow, and consequently its ability to distribute earnings, is solely dependent upon the cash flow its subsidiaries receive from the Driftwood Project and its other operations. Tellurian’s ability to complete the project, as discussed elsewhere in this section, is dependent upon its and its subsidiaries’ ability to obtain and maintain necessary regulatory approvals and raise the capital necessary to fund the development of the project. We expect that cash flows from our operations will be reinvested in the business rather than used to fund dividends, that pursuing our strategy will require substantial amounts of capital, and that the required capital will exceed cash flows from operations for a significant period.

Tellurian's ability to pay dividends in the future is uncertain and will depend on a variety of factors, including limitations on the ability of it or its subsidiaries to pay dividends under applicable law and/or the terms of debt or other agreements, and the judgment of the Board of Directors or other governing body of the relevant entity.

We may be unable to fulfill our obligations under our debt agreements.

We have issued senior notes as described in Note 8, *Borrowings*, and Note 19, *Subsequent Events* of our Notes to Consolidated Financial Statements included in this report. In addition to the principal and interest on those notes, we may also owe additional cash payments under certain of the notes based on the trading price of our common stock over specified periods. Our ability to generate cash flows from operations or obtain refinancing capital sufficient to pay interest, principal and other amounts due on our indebtedness will depend on our future operating performance and financial condition and the availability of refinancing debt or equity capital, which will be affected by prevailing commodity prices and economic conditions and financial, business and other factors, many of which are beyond our control. If we successfully sell our Upstream properties, we expect to reduce our indebtedness; however, such a sale would also deprive us of what is currently our only revenue producing asset. Our inability to generate adequate cash flows from operations could adversely affect our ability to execute our overall business plan, and we could be required to sell assets, reduce our capital expenditures or seek refinancing debt or equity capital to satisfy the requirements of the debt agreements. These alternative measures may be unavailable or inadequate, in which case we could be forced into bankruptcy or liquidation, and may themselves adversely affect our overall business strategy. In addition, one or both of the indentures governing our Replacement Notes contain covenants, including limitations on our ability to incur additional indebtedness and a minimum cash covenant, that could prevent us from pursuing certain business strategies or opportunities. If we are unable to comply with these covenants, amounts due under the notes could be accelerated.

Pandemics or disease outbreaks, such as the COVID-19 pandemic, may adversely affect our efforts to reach a final investment decision with respect to the Driftwood Project.

Pandemics or disease outbreaks such as the COVID-19 pandemic may have a variety of adverse effects on our business, including by depressing commodity prices and the market value of our securities. Prospects for the development and financing of the Driftwood Project are based in part on factors including global economic conditions that have been, and may continue to be, adversely affected by the COVID-19 pandemic.

Risks Relating to Our Common Stock

The price of our common stock has been and may continue to be highly volatile, which may make it difficult for shareholders to sell our common stock when desired or at attractive prices.

The market price of our common stock is highly volatile, and we expect it to continue to be volatile for the foreseeable future. Adverse events could trigger a significant decline in the trading price of our common stock, including, among others, failure to obtain necessary permits, unfavorable changes in commodity prices or commodity price expectations, adverse regulatory developments, loss of a relationship with a partner, litigation, departures of key personnel, and failures to advance the Driftwood Project on the terms or within the time periods anticipated. Furthermore, general market conditions, including the level of, and fluctuations in, the trading prices of equity securities generally could affect the price of our stock. The stock markets frequently experience price and volume volatility that affects many companies' stock prices, often in ways unrelated to the operating performance of those companies. These fluctuations may affect the market price of our common stock. The trading price of our common stock during 2023 was as low as \$0.48 per share and as high as \$2.15 per share.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock by us or our major shareholders.

Sales of a substantial number of shares of our common stock in the market by us or any of our major shareholders, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares in the public market, or the possibility of such sales, could impair our ability to raise capital through the sale of additional equity securities.

In addition, in the future, we may issue shares of our common stock, or securities convertible into our common stock, in connection with acquisitions of assets or businesses or for other purposes. Such issuances may result in dilution to our existing stockholders and could have an adverse effect on the market value of shares of our common stock, depending on market conditions at the time, the terms of the issuance, and if applicable, the value of the business or assets acquired and our success in exploiting the properties or integrating the businesses we acquire.

Non-U.S. holders of our common stock, in certain situations, could be subject to U.S. federal income tax upon sale, exchange or disposition of our common stock.

We are currently, and may remain in the future, a U.S. real property holding corporation for U.S. federal income tax purposes because the fair market value of our assets that consist of “United States real property interests,” as defined in the Internal Revenue Code of 1986, as amended, and applicable Treasury regulations, constitutes at least 50% of the combined fair market value of our real estate interests and other business assets. As a result, under the Foreign Investment in Real Property Tax Act, or FIRPTA, certain non-U.S. investors could be subject to U.S. federal income tax on any gain from the disposition of shares of our common stock, in which case they would also be required to file U.S. tax returns with respect to such gain. In general, whether these FIRPTA provisions apply in such case would depend on the amount of our common stock that such non-U.S. investors hold. In addition, such non-U.S. investors could be subject to withholding in such case if, at the time they dispose of their shares, our common stock is not regularly traded on an established securities market within the meaning of the applicable Treasury regulations. So long as our common stock continues to be regularly traded on an established securities market, only a non-U.S. investor who has owned, actually or constructively, more than 5% of our common stock at any time during the shorter of (i) the five-year period ending on the date of disposition and (ii) the non-U.S. investor’s holding period for its shares may be subject to U.S. federal income tax on the disposition of our common stock under FIRPTA.

Risks Relating to Our LNG Business

Various economic and political factors could negatively affect the development, construction and operation of LNG facilities, including the Driftwood terminal, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Commercial development of an LNG facility takes a number of years, requires substantial capital investment and may be delayed by factors such as:

- increased construction costs;
- economic downturns, increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of natural gas or LNG outside of the United States, which might decrease the expected returns relating to investments in LNG projects;
- the inability of project owners or operators to obtain governmental approvals to construct or operate LNG facilities;
- any renegotiation of EPC agreements that may be required in the event of delays in a final investment decision or other failures to meet specified deadlines; and
- political unrest or local community resistance to the siting of LNG facilities due to safety, environmental or security concerns.

Our failure to execute our business plan within budget and on schedule could materially adversely affect our business, financial condition, operating results, liquidity and prospects.

Tellurian’s estimated costs for the Driftwood Project and other projects may not be accurate and are subject to change.

Cost estimates for the Driftwood Project and other projects we may pursue are only approximations of the actual costs of construction. Cost estimates may be inaccurate and may change due to various factors, such as cost overruns, change orders, delays in construction, legal and regulatory requirements, site issues, increased component and material costs, escalation of labor costs, labor disputes, changes in commodity prices, changes in foreign currency exchange rates, increased spending to maintain Tellurian’s construction schedule and other factors. For example, new or increased tariffs on materials needed in the construction process could materially increase construction costs, as could supply chain issues affecting long lead-time items. Our estimate of the cost of construction of the Driftwood terminal is based on the prices set forth in our LSTK EPC agreements with Bechtel and those prices are subject to adjustment by change orders, including for consideration of certain increased costs. Our failure to achieve our cost estimates could materially adversely affect our business, financial condition, operating results, liquidity and prospects.

If third-party pipelines and other facilities interconnected to the Driftwood Project become unavailable to transport natural gas, this could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

We will depend upon third-party pipelines and other facilities that will provide natural gas delivery options to our natural gas operations and the Driftwood Project. If the construction of new or modified pipeline connections is not completed on schedule or any pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to meet future LNG sale and purchase agreement obligations and continue shipping natural gas from producing operations or regions to end markets could be restricted, thereby

reducing our revenues. This could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

Tellurian's ability to generate cash will depend upon it entering into contracts with third-party customers, the terms of those contracts and the performance of those customers under those contracts.

We expect to enter into commercial agreements with third-party customers for the sale of LNG from the Driftwood Project. Our ability to generate revenue from these contracts will depend upon, among other factors, LNG prices and our ability to finance and complete the construction of the project. Tellurian's business strategy may change regarding how and when the proposed Driftwood Project's export capacity is marketed. Also, Tellurian's business strategy may change due to an inability to enter into agreements with customers or based on a variety of factors, including the future price outlook, supply and demand of LNG, natural gas liquefaction capacity, and global regasification capacity. If our efforts to market the proposed Driftwood Project and the LNG it will produce are not successful, Tellurian's business, results of operations, financial condition and prospects may be materially and adversely affected.

We may not be able to purchase, receive or produce sufficient natural gas to satisfy our delivery obligations under any LNG sale and purchase agreements, which could have an adverse effect on us.

Under LNG sale and purchase agreements with our customers, we may be required to make available to them a specified amount of LNG at specified times. However, we may not be able to acquire or produce sufficient quantities of natural gas or LNG to satisfy those obligations, which may provide affected customers with the right to terminate their LNG sale and purchase agreements. Our failure to purchase, receive or produce sufficient quantities of natural gas or LNG in a timely manner could have an adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The construction and operation of the Driftwood Project remain subject to ongoing compliance obligations and further approvals, and some approvals may be subject to further conditions, review and/or revocation.

The design, construction and operation of LNG export terminals is a highly regulated activity. The approval of FERC under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, is required to construct and operate an LNG terminal. Such approvals and authorizations are often subject to ongoing conditions imposed by regulatory agencies, and additional approval and permit requirements may be imposed. Tellurian and its affiliates will be required to obtain and maintain governmental approvals and authorizations to implement its proposed business strategy, which includes the construction and operation of the Driftwood Project. Although all the major permits required for construction and operation of the Driftwood terminal and Driftwood pipeline have been obtained, we must still satisfy various conditions of our permits during the construction process. Additionally, numerous permits and approvals will be required in connection with other assets, including our upstream operations. Certain environmental groups have opposed our efforts to obtain and maintain the permits necessary to grow our operations pursuant to our strategy.

There is no assurance that Tellurian will obtain and maintain these governmental permits, approvals and authorizations, and failure to obtain and maintain any of these permits, approvals or authorizations could have a material adverse effect on its business, results of operations, financial condition and prospects.

Tellurian will be dependent on third-party contractors for the successful completion of the Driftwood terminal, and these contractors may be unable to complete the Driftwood terminal.

The construction of the Driftwood terminal is expected to take several years, will be confined to a limited geographic area and could be subject to delays, cost overruns, labor disputes and other factors that could adversely affect financial performance or impair Tellurian's ability to execute its proposed business plan. Timely and cost-effective completion of the Driftwood terminal in compliance with agreed-upon specifications will be highly dependent upon the performance of Bechtel and other third-party contractors pursuant to their agreements. However, Tellurian has not yet entered into definitive agreements with all of the contractors, advisors and consultants necessary for the development and construction of the Driftwood terminal. Tellurian may not be able to successfully enter into such construction contracts on terms or at prices that are acceptable to it.

Further, faulty construction that does not conform to Tellurian's design and quality standards may have an adverse effect on Tellurian's business, results of operations, financial condition and prospects. For example, improper equipment installation may lead to a shortened life of Tellurian's equipment, increased operations and maintenance costs or a reduced availability or production capacity of the affected facility. The ability of Tellurian's third-party contractors to perform successfully under any agreements to be entered into is dependent on a number of factors, including force majeure events and such contractors' ability to:

- design, engineer and receive critical components and equipment necessary for the Driftwood terminal to operate in accordance with specifications and address any start-up and operational issues that may arise in connection with the commencement of commercial operations;
- attract, develop and retain skilled personnel, engage and retain third-party subcontractors, and address any labor issues that may arise;
- post required construction bonds and comply with the terms thereof, and maintain their own financial condition, including adequate working capital;
- adhere to any warranties that the contractors provide in their EPC contracts; and
- respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control, and manage the construction process generally, including engaging and retaining third-party contractors, coordinating with other contractors and regulatory agencies and dealing with inclement weather conditions.

Furthermore, Tellurian may have disagreements with its third-party contractors about different elements of the construction process, which could lead to the assertion of rights and remedies under the related contracts, resulting in a contractor's unwillingness to perform further work on the relevant project. The risk of disagreements with contractors and other construction issues such as increased costs and delays may be exacerbated by inflation, supply chain disruptions and other market conditions. Tellurian may also face difficulties in commissioning a newly constructed facility. Any significant delays in the development of the Driftwood terminal could materially and adversely affect Tellurian's business, results of operations, financial condition and prospects. The construction of pipelines comprising part of the Driftwood Project will be required for the long-term operations of the Driftwood terminal and will be subject to similar risks.

Tellurian's construction and operations activities are subject to a number of development risks, operational hazards, regulatory approvals and other risks, which could cause cost overruns and delays and could have a material adverse effect on its business, results of operations, financial condition, liquidity and prospects.

Siting, development and construction of the Driftwood Project and related pipelines will be subject to the risks of delay or cost overruns inherent in any construction project resulting from numerous factors, including, but not limited to, the following:

- difficulties or delays in obtaining, or failure to obtain, sufficient equity or debt financing on reasonable terms;
- failure to obtain all necessary government and third-party permits, approvals and licenses for the construction and operation of the Driftwood Project or any other proposed LNG facilities or related pipelines;
- difficulties in engaging qualified contractors necessary for the construction of the contemplated Driftwood Project or related pipelines;
- shortages of equipment, material or skilled labor;
- natural disasters and catastrophes, such as hurricanes, explosions, fires, floods, industrial accidents, pandemics and terrorism;
- unscheduled delays in the delivery of ordered materials;
- work stoppages and labor disputes;
- competition with other domestic and international LNG export terminals;
- unanticipated changes in domestic and international market demand for and supply of natural gas and LNG, which will depend in part on supplies of and prices for alternative energy sources and the discovery of new sources of natural resources;
- unexpected or unanticipated need for additional improvements; and
- adverse general economic conditions.

Delays beyond the estimated development periods, as well as cost overruns, could increase the cost of completion beyond the amounts that are currently estimated, which could require Tellurian to obtain additional sources of financing to fund its activities until the proposed Driftwood terminal is constructed and operational (which could cause further delays). Any delay in completion of the Driftwood Project may also cause a delay in the receipt of revenues projected from the Driftwood Project or cause a loss of one or more customers. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects. Similar risks may affect the construction of other facilities and projects we elect to pursue.

Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect Tellurian's LNG business and the performance of our customers and could lead to the reduced development of LNG projects worldwide.

Tellurian's plans and expectations regarding its business and the development of domestic LNG facilities and projects are generally based on assumptions about the future price of natural gas and LNG and the conditions of the global natural gas and LNG markets. Natural gas and LNG prices have been, and are likely to remain in the future, volatile and subject to wide fluctuations that are difficult to predict. Such fluctuations may be caused by various factors, including, but not limited to, one or more of the following:

- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient or oversupply of LNG tanker capacity;
- weather conditions;
- changes in demand for natural gas, including as a result of disruptive events such as the Russian invasion of Ukraine, conflicts in the Middle East and the COVID-19 pandemic;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- decreased oil and natural gas exploration activities, which may decrease the production of natural gas;
- cost improvements that allow competitors to offer LNG regasification services or provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;
- political conditions in natural gas producing regions; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

Adverse trends or developments affecting any of these factors could result in decreases in the price of LNG and/or natural gas, which could materially and adversely affect the performance of our customers and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects. The profitability of the LNG SPAs we expect to enter into will depend in part on the relationship between the costs we incur in producing or purchasing natural gas and the then-current index prices when sales occur. An adverse change in that relationship, whether resulting from an increase in our costs, a decline in the index prices or both, could make sales under the agreements less profitable or could require us to sell at a loss. These risks have increased in some recent periods as higher commodity prices have resulted in cargos becoming generally more expensive, therefore increasing our exposure to potential losses.

Technological innovation may render Tellurian's anticipated competitive advantage or its processes obsolete.

Tellurian's success will depend on its ability to create and maintain a competitive position in the natural gas liquefaction industry. In particular, although Tellurian plans to construct the Driftwood terminal using proven technologies that it believes provide it with certain advantages, Tellurian does not have any exclusive rights to any of the technologies that it will be utilizing. In addition, the technology Tellurian anticipates using in the Driftwood Project may be rendered obsolete or uneconomical by legal or regulatory requirements, technological advances, more efficient and cost-effective processes or entirely different approaches developed by one or more of its competitors or others, which could materially and adversely affect Tellurian's business, results of operations, financial condition, liquidity and prospects.

Failure of exported LNG to be a competitive source of energy for international markets could adversely affect our customers and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Operations of the Driftwood Project will be dependent upon our ability to deliver LNG supplies from the U.S., which is primarily dependent upon LNG being a competitive source of energy internationally. The success of our business plan is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be supplied from North America and delivered to international markets at a lower cost than the cost of alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside the U.S., which could increase the available supply of natural gas outside the U.S. and could result in natural gas in those markets being available at a lower cost than that of LNG exported to those markets.

Factors which may negatively affect potential demand for LNG from our liquefaction projects are diverse and include, among others:

- increases in worldwide LNG production capacity and availability of LNG for market supply;

- increases in demand for LNG but at levels below those required to maintain current price equilibrium with respect to supply;
- increases in the cost to supply natural gas feedstock to our liquefaction project;
- decreases in the cost of competing sources of natural gas or alternative sources of energy such as coal, heavy fuel oil, diesel, nuclear, hydroelectric, wind and solar;
- decreases in the price of non-U.S. LNG, including decreases in price as a result of contracts indexed to lower oil prices;
- increases in capacity and utilization of nuclear power and related facilities;
- increases in the cost of LNG shipping, including due to disruptions of global LNG maritime trade routes; and
- displacement of LNG by pipeline natural gas or alternative fuels in locations where access to these energy sources is not currently available.

Political instability in foreign countries that import natural gas, or strained relations between such countries and the U.S., may also impede the willingness or ability of LNG suppliers, purchasers and merchants in such countries to import LNG from the U.S. Furthermore, some foreign purchasers of LNG may have economic or other reasons to obtain their LNG from non-U.S. markets or our competitors' liquefaction facilities in the U.S.

As a result of these and other factors, LNG may not be a competitive source of energy internationally. The failure of LNG to be a competitive supply alternative to local natural gas, oil and other alternative energy sources in markets accessible to our customers could adversely affect the ability of our customers to deliver LNG from the U.S. on a commercial basis. Any significant impediment to the ability to deliver LNG from the U.S. generally, or from the Driftwood Project specifically, could have a material adverse effect on our customers and our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

There may be shortages of LNG vessels worldwide, which could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

The construction and delivery of LNG vessels require significant capital and long construction lead times, and the availability of the vessels could be delayed to the detriment of Tellurian's business and customers due to a variety of factors, including, but not limited to, the following:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances at shipyards;
- bankruptcies or other financial crises of shipbuilders;
- quality or engineering problems;
- weather interference or catastrophic events, such as a major earthquake, tsunami, or fire; or
- shortages of or delays in the receipt of necessary construction materials.

Any of these factors could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

We will rely on third-party engineers to estimate the future capacity ratings and performance capabilities of the Driftwood terminal, and these estimates may prove to be inaccurate.

We will rely on third parties for the design and engineering services underlying our estimates of the future capacity ratings and performance capabilities of the Driftwood terminal. Any of our LNG facilities, when constructed, may not have the capacity ratings and performance capabilities that we intend or estimate. Failure of any of our facilities to achieve our intended capacity ratings and performance capabilities could prevent us from achieving the commercial start dates under future LNG sale and purchase agreements and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The Driftwood Project and related pipelines will be subject to a number of environmental and safety laws and regulations that impose significant compliance costs, and existing and future environmental, safety and similar laws and regulations could result in increased compliance costs, liabilities or additional operating restrictions.

We are and will be subject to extensive federal, state and local environmental and safety regulations and laws, including regulations and restrictions related to discharges and releases to the air, land and water and the handling, storage, generation and disposal of hazardous materials and solid and hazardous wastes in connection with the development,

construction and operation of our LNG facilities and pipelines. Failure to comply with these regulations and laws could result in the imposition of administrative, civil and criminal sanctions.

These regulations and laws, which include the CAA, the Oil Pollution Act, CERCLA, the CWA and RCRA, and analogous state and local laws and regulations, will restrict, prohibit or otherwise regulate the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our facilities. These laws and regulations will require and have required us to obtain and maintain permits with respect to our facilities, provide governmental authorities with access to our facilities for inspection and provide reports related to compliance. Federal and state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties, the denial or revocation of permits necessary for our operations, governmental orders to shut down our facilities or capital expenditures related to pollution control equipment or remediation measures that could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

As the ultimate owner and the operator of the Driftwood Project and other related assets we or our subsidiaries could be liable for the costs of investigating and cleaning up hazardous substances released into the environment and for damage to natural resources, whether caused by us or our contractors or existing at the time construction commences. Hazardous substances present in soil, groundwater and dredge spoils may need to be processed, disposed of or otherwise managed to prevent releases into the environment. Tellurian or its affiliates may be responsible for the investigation, cleanup, monitoring, removal, disposal and other remedial actions with respect to hazardous substances on, in or under properties that Tellurian owns or operates, or released at a site where materials are disposed of from our operations, without regard to fault or the origin of such hazardous substances. Such liabilities may involve material costs that are unknown and not predictable.

Changes in legislation and regulations could have a material adverse impact on Tellurian's business, results of operations, financial condition, liquidity and prospects.

Tellurian's business will be subject to governmental laws, rules, regulations and permits that impose various restrictions and obligations that may have material effects on the results of our operations. Each of the applicable regulatory requirements and limitations is subject to change, either through new regulations enacted on the federal, state or local level, or by new or modified regulations that may be implemented under existing law. The nature and effects of these changes in laws, rules, regulations and permits may be unpredictable and may have material effects on our business. Future legislation and regulations, such as those relating to the transportation and security of LNG exported from our proposed LNG facilities through the Calcasieu Ship Channel, could cause additional expenditures, restrictions and delays in connection with the proposed LNG facilities and their construction, the extent of which cannot be predicted and which may require Tellurian to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased construction or compliance costs or additional operating costs and restrictions could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

Our operations will be subject to significant risks and hazards, one or more of which may create significant liabilities and losses that could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

We will face numerous risks in developing and conducting our operations. For example, the plan of operations for the proposed Driftwood Project and related assets is subject to the inherent risks associated with LNG, pipeline and upstream operations, including explosions, pollution, leakage or release of toxic substances, fires, hurricanes and other adverse weather conditions, leakage of hydrocarbons, and other hazards, each of which could result in significant delays in commencement or interruptions of operations and/or result in damage to or destruction of the proposed Driftwood Project, or upstream assets, or damage to persons and property. In addition, operations at the proposed Driftwood Project, upstream assets, and vessels or facilities of third parties on which Tellurian's operations are dependent could face possible risks associated with acts of aggression or terrorism.

Hurricanes have damaged coastal and inland areas located in the Gulf Coast area, resulting in disruption and damage to certain LNG terminals located in the area. Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, or interruption of operations at, the Driftwood terminal or related infrastructure, as well as delays or cost increases in the construction and the development of the Driftwood terminal or other facilities. Storms, disasters and accidents could also damage or interrupt the activities of vessels that we or third parties operate in connection with our LNG business. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods and rising sea levels. If any such effects were to occur, they could have an adverse effect on our coastal operations.

Our LNG business will face other types of risks and liabilities as well. For instance, our LNG marketing activities expose us to possible financial losses, including the risk of losses resulting from adverse changes in the index prices upon

which contracts for the purchase and sale of LNG cargos are based. Our LNG marketing activities are also subject to various domestic and international regulatory and foreign currency risks.

Tellurian does not, nor does it intend to, maintain insurance against all of these risks and losses, and many risks are not insurable. Tellurian may not be able to maintain desired or required insurance in the future at rates that it considers reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on Tellurian's business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Risks Relating to Our Natural Gas and Oil Operating Activities

Our planned sale of upstream natural gas assets may not be successful and may not provide the benefits we anticipate.

On February 6, 2024, we announced that we are exploring a sale of our upstream natural gas assets. This sale is an important part of our efforts to maintain adequate liquidity, reduce our indebtedness, maintain compliance with our debt covenants and continue as a going concern. We have not reached any agreement with any potential buyer of those assets and we may not be able to do so. Moreover, if we are able to reach such an agreement, we may not be able to close the transaction. Further, the proceeds of the transaction may be less than we expect or we may have post-closing liabilities that ultimately reduce those proceeds. Finally, it may take longer than we expect to complete the transaction, and any delay may adversely impact our ability to achieve our liquidity and debt-reduction goals.

Acquisitions of natural gas and oil properties are subject to the uncertainties of evaluating reserves and potential liabilities, including environmental uncertainties.

We may in the future pursue acquisitions of natural gas and oil properties from time to time. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include reserves, development potential, future commodity prices, operating costs, title issues, and potential environmental and other liabilities. Such assessments are inexact, and their accuracy is inherently uncertain. In connection with our assessments, we perform due diligence that we believe is generally consistent with industry practices.

However, our due diligence activities are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition, and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface, and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we may acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. We may not be entitled to contractual indemnification associated with acquired properties. We may acquire interests in properties on an "as is" basis with limited or no remedies for breaches of representations and warranties.

Therefore, we could incur significant unknown liabilities, including environmental liabilities or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks, and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

In addition, we may not be able to identify attractive acquisition opportunities if we attempt to do so. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. It may be difficult to agree on the economic terms of a transaction, as a potential seller may be unwilling to accept a price that we believe to be appropriately reflective of prevailing economic conditions.

Natural gas and oil prices fluctuate widely, and lower prices for an extended period of time may have a material adverse effect on the profitability of our natural gas or oil operating activities.

The revenues, operating results and profitability of our natural gas or oil operating activities will depend significantly on the prices we receive for the natural gas or oil we sell. If we do not sell our Upstream properties as planned, we will require substantial expenditures to replace reserves, sustain production and fund our business plans. Low natural gas or oil prices can negatively affect the amount of cash available for acquisitions and capital expenditures and our ability to raise additional capital and, as a result, could have a material adverse effect on our revenues, cash flow and reserves. In addition, low natural gas or oil prices may result in write-downs of our natural gas or oil properties, such as the \$81.1 million impairment charge we incurred in 2020. Conversely, any substantial or extended increase in the price of natural gas would adversely affect the competitiveness of LNG as a source of energy (as discussed above in "— Risks Relating to Our LNG Business — Failure of exported LNG to be a competitive source of energy for international markets could adversely affect our customers and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects").

Historically, the markets for natural gas and oil have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas or oil prices may result from relatively minor changes in the supply of or demand for natural gas or oil, market uncertainty and other factors that are beyond our control. The volatility of the energy markets makes it extremely difficult to predict future natural gas or oil price movements, and we will be unable to fully hedge our exposure to natural gas or oil prices.

If we do not sell our Upstream properties, significant capital expenditures may be required to develop those properties.

The development of upstream oil and gas properties often requires substantial capital expenditures. If we do not sell our properties, we intend to fund our capital expenditures for our natural gas and oil operating activities through cash on hand and financing transactions that may include public or private equity or debt offerings or borrowings under additional debt agreements. Our ability to generate operating cash flow in the future will be subject to a number of risks and variables, such as the level of production from existing wells, the price of natural gas or oil, our success in developing and producing new reserves and the other risk factors discussed in this section. If we are unable to fund our capital expenditures for natural gas or oil operating activities, we could experience a curtailment of our development activity and a decline in our natural gas or oil production, and that could reduce our production and revenue and affect our ability to pursue our overall strategy.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower natural gas or oil prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, reduce our production and materially and adversely affect our financial condition and results of operations.

Drilling and producing operations can be hazardous and may expose us to liabilities.

Natural gas and oil operations are subject to many risks, including well blowouts, explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, leakages or releases of hydrocarbons, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. For our non-operated properties, we will be dependent on the operator for regulatory compliance and for the management of these risks.

These risks could materially and adversely affect our revenues and expenses by reducing production from wells, causing wells to be shut in or otherwise negatively impacting our projected economic performance. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- facility or equipment malfunctions and equipment failures or accidents;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

Any of these events could expose us to liabilities, monetary penalties or interruptions in our business operations. In addition, certain of these risks are greater for us than for many of our competitors in that some of the natural gas we produce has a high sulphur content (sometimes referred to as “sour” gas), which increases its corrosiveness and the risk of an accidental release of hydrogen sulfide gas, exposure to which can be fatal. We may not maintain insurance against such risks, and some risks are not insurable. Even when we are insured, our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future, we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which we are not fully insured may expose us to liabilities.

Our drilling efforts may not be profitable or achieve our targeted returns and our reserve estimates are based on assumptions that may not be accurate.

Drilling for natural gas and oil may involve unprofitable efforts from wells that are either unproductive or productive but do not produce sufficient commercial quantities to cover drilling, completion, operating and other costs. In addition, even a commercial well may have production that is less, or costs that are greater, than we projected. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling

operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. Natural gas and oil reserve engineering requires estimates of underground accumulations of hydrocarbons and assumptions concerning future prices, production rates and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be incorrect. Our estimates of proved reserves are determined based in part on costs at the date of the estimate. Any significant variance from these costs could greatly affect our estimates of reserves.

Our natural gas operating activities are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner and feasibility of doing business, and further regulation in the future could increase costs, impose additional operating restrictions and cause delays.

Our natural gas operating activities and properties are (and to the extent that we acquire oil producing properties, these properties will be) subject to numerous federal, regional, state and local laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- conduct of drilling, completion, production and midstream activities;
- amounts and types of emissions and discharges;
- generation, management, and disposal of hazardous substances and waste materials;
- reclamation and abandonment of wells and facility sites; and
- remediation of contaminated sites.

In addition, these laws and regulations may result in substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area.

Environmental laws and regulations change frequently, and these changes are difficult to predict or anticipate. Future environmental laws and regulations imposing further restrictions on the emission of pollutants into the air, discharges into state or U.S. waters, wastewater disposal and hydraulic fracturing, or the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our natural gas or oil production. We cannot predict the actions that future regulation will require or prohibit, but our business and operations could be subject to increased operating and compliance costs if certain regulatory proposals are adopted. In addition, such regulations may have an adverse impact on our ability to develop and produce our reserves.

Federal, state or local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Laws or regulations that could impose more stringent permitting, public disclosure and/or well construction requirements on hydraulic fracturing operations are proposed from time to time at the federal, state and local levels. Regulatory bodies and others from time to time assess, among other things, the risks of groundwater contamination and earthquakes caused by hydraulic fracturing and other exploration and production activities. Depending on the outcome of these assessments, federal and state legislatures and agencies may seek to further regulate or even ban such activities, as some state and local governments have already done. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions. Among other things, this could adversely affect the cost to produce natural gas, either by us or by third-party suppliers, and therefore LNG, and this could adversely affect the competitiveness of LNG relative to other sources of energy.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and services could adversely affect our ability to execute our development plans within budgeted amounts and on a timely basis.

The demand for qualified and experienced field and technical personnel to conduct our operations can fluctuate significantly, often in correlation with hydrocarbon prices. The price of services and equipment may increase in the future and availability may decrease.

In addition, it is possible that oil prices could increase without a corresponding increase in natural gas prices, which could lead to increased demand and prices for equipment, facilities and personnel without an increase in the price at which we sell our natural gas to third parties. This could have an adverse effect on the competitiveness of the LNG produced from the Driftwood terminal. In this scenario, necessary equipment, facilities and services may not be available to us at economical prices. Any shortages in availability or increased costs could delay us or cause us to incur significant additional expenditures,

which could have a material adverse effect on the competitiveness of the natural gas we sell and therefore on our business, financial condition and results of operations.

Our natural gas and oil production may be adversely affected by pipeline and gathering system capacity constraints.

Our natural gas and oil production activities rely on third parties to meet our needs for midstream infrastructure and services. Capital constraints and public opposition to projects could limit the construction of new infrastructure by us and third parties. In addition, increased production from us and other operators could lead to capacity constraints. We may experience delays in producing and selling natural gas or oil from time to time when adequate midstream infrastructure and services are not available. Such an event could reduce our production or result in other adverse effects on our business.

Risks Relating to Our Business in General

We are pursuing a strategy of participating in multiple aspects of the natural gas business, which exposes us to risks.

We plan to develop, own and operate a global natural gas business and to deliver natural gas to customers worldwide. We may not be successful in executing our strategy in the near future, or at all. Our management will be required to understand and manage a diverse set of business opportunities, which may distract their focus and make it difficult to be successful in increasing value for shareholders.

Tellurian will be subject to risks related to doing business in, and having counterparties based in, foreign countries.

Tellurian may engage in operations or make substantial commitments and investments, or enter into agreements with counterparties, located outside the U.S., which would expose Tellurian to political, governmental, and economic instability, foreign currency exchange rate fluctuations and corruption risk.

Any disruption caused by these factors could harm Tellurian's business, results of operations, financial condition, liquidity and prospects. Risks associated with operations, commitments and investments outside of the U.S. include but are not limited to risks of:

- currency fluctuations;
- war or terrorist attack;
- expropriation or nationalization of assets;
- renegotiation or nullification of existing contracts;
- changing political conditions;
- changing laws and policies affecting trade, taxation, and investment;
- multiple taxation due to different tax structures;
- compliance with laws and regulations of foreign jurisdictions, and with U.S. laws and regulations related to foreign operations;
- general hazards associated with the assertion of sovereignty over areas in which operations are conducted; and
- the unexpected credit rating downgrade of countries in which Tellurian's LNG customers are based.

Because Tellurian's reporting currency is the U.S. dollar, any of the operations conducted outside the U.S. or denominated in foreign currencies would face additional risks of fluctuating currency values and exchange rates, hard currency shortages and controls on currency exchange. In addition, Tellurian would be subject to the impact of foreign currency fluctuations and exchange rate changes on its financial reports when translating the value of its assets, liabilities, revenues and expenses from operations outside of the U.S. into U.S. dollars at then-applicable exchange rates. These translations could result in changes to the results of operations from period to period.

Potential legislative and regulatory actions addressing climate change, public views about climate change and the physical effects of climate change could significantly impact us.

In recent years, various federal and state governments and regional organizations have enacted or proposed new legislation and regulations governing or restricting the emission of GHGs, including GHG emissions from oil and natural gas production equipment and facilities. At the federal level, for example, the EPA has issued regulations that require GHG emissions reporting for the Driftwood Project and related operations and proposed new regulations regarding methane emissions from our operations. Additional legislative and/or regulatory proposals targeting the elimination of or restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs or otherwise impact our financial results. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program. Even without additional federal legislation or regulation of GHG emissions, states and other governmental

authorities may impose these requirements either directly or indirectly. For example, many states and other governmental authorities have set specific targets for future GHG reductions or created renewable portfolio standards that require the procurement of certain amounts of renewable energy.

Many scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. Such effects could adversely affect our facilities and operations, and have an adverse effect on our financial condition and results of operations. Further, adverse weather events may accelerate changes in laws and regulations aimed at reducing GHG emissions, which could result in declining demand for natural gas and LNG, and could adversely affect our business generally. In addition, many customers are focusing more on sustainability and the environmental impacts of operations of companies. Responses to such customer demands or an inability to respond to potential customer demands with respect to these issues could have an impact on our financial results. Furthermore, some governmental or business entities have set voluntary carbon emissions targets or are otherwise subject to regulatory limits on their carbon emissions. Any of these developments could result in less demand for our products and, in turn, affect our financial results.

For additional information on recent regulatory changes relating to climate change, please refer to Item 1, *Governmental Regulations*.

A major health and safety incident relating to our business could be costly in terms of potential liabilities and reputational damage.

Tellurian is subject to extensive federal, state and local health and safety regulations and laws. Health and safety performance is critical to the success of all areas of our business. Any failure in health and safety performance may result in personal harm or injury, penalties for non-compliance with relevant laws and regulations or litigation, and a failure that results in a significant health and safety incident is likely to be costly in terms of potential liabilities. Such a failure could generate public concern and have a corresponding impact on our reputation and our relationships with relevant regulatory agencies and local communities, which in turn could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Our operations could also become subject to increased governmental scrutiny that may result in additional oversight at a significant incremental cost.

A terrorist attack or military incident could result in delays in, or cancellation of, construction or closure of our facilities or other disruption to our business.

A terrorist or military incident could disrupt our business. For example, an incident involving an LNG carrier or LNG facility may result in delays in, or cancellation of, construction of new LNG facilities, including our proposed LNG facilities, which would increase our costs and decrease our cash flows. A terrorist incident may also result in the temporary or permanent closure of Tellurian facilities or operations, which could increase costs and decrease cash flows, depending on the duration of the closure. Our operations could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost. In addition, the threat of terrorism and the impact of military campaigns may lead to continued volatility in prices for natural gas or oil that could adversely affect Tellurian's business and customers, including by impairing the ability of Tellurian's suppliers or customers to satisfy their respective obligations under Tellurian's commercial agreements.

Cyber-attacks targeting systems and infrastructure used in our business may adversely impact our operations.

We depend on digital technology in many aspects of our business, including the processing and recording of financial and operating data, analysis of information, and communications with our employees and third parties. Cyber-attacks on our systems and those of third-party vendors and other counterparties occur frequently and have grown in sophistication. A successful cyber-attack on us or a vendor or other counterparty could have a variety of adverse consequences, including theft of proprietary or commercially sensitive information, data corruption, interruption in communications, disruptions to our existing or planned activities or transactions, and damage to third parties, any of which could have a material adverse impact on us. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks.

Failure to retain and attract key personnel such as Tellurian's Chairman, Chief Executive Officer or other skilled professional and technical employees could have an adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

The success of Tellurian's business relies heavily on key personnel such as its Chairman and Chief Executive Officer. Should such persons be unable to perform their duties on behalf of Tellurian, or should Tellurian be unable to retain or attract other members of management, Tellurian's business, results of operations, financial condition, liquidity and prospects could be materially impacted.

Additionally, we are dependent upon an available labor pool of skilled employees. We will compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct and operate our facilities and to provide our customers with the highest quality service. A shortage of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult for us to attract and retain qualified personnel and could require an increase in the wage and benefits packages that we offer, or increases in the amounts we are obligated to pay our contractors, thereby increasing our operating costs. Any increase in our operating costs could materially and adversely affect our business, financial condition, operating results, liquidity and prospects.

Competition is intense in the energy industry and some of Tellurian’s competitors have greater financial, technological and other resources.

Tellurian plans to operate in various aspects of the natural gas and oil business and will face intense competition in each area. Depending on the area of operations, competition may come from independent, technology-driven companies, large, established companies and others.

For example, an increasing number of competing companies have secured access to, or are pursuing the development or acquisition of, LNG facilities to serve the North American natural gas market, including other proposed liquefaction facilities in North America. Tellurian may face competition from major energy companies and others in pursuing its proposed business strategy to provide liquefaction and export products and services at its proposed Driftwood terminal. In addition, competitors have developed and are developing additional LNG terminals in other markets, which will also compete with our proposed LNG facilities.

As another example, our business will face competition in, among other things, buying and selling reserves and leases and obtaining goods and services needed to operate properties and market natural gas and oil. Competitors include multinational oil companies, independent production companies and individual producers and operators.

Many of our competitors have longer operating histories, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than Tellurian currently possesses. The superior resources that some of these competitors have available for deployment could allow them to compete successfully against Tellurian, which could have a material adverse effect on Tellurian’s business, results of operations, financial condition, liquidity and prospects.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We recognize the importance of assessing, identifying and managing material risks associated with any “cybersecurity threat,” as such term is defined in Item 106(a) of Regulation S-K. We assess cybersecurity risk on an annual basis and whenever management deems there to be a significant change to exposure or external threats. We also have several enterprise-wide and business unit-specific cybersecurity processes, technologies, and controls to aid in our efforts to identify, evaluate, and respond to such cybersecurity risk. As part of our cybersecurity risk management processes, we leverage our membership in the Oil and Natural Gas Information Sharing and Analysis Center (ONG-ISAC) and utilize carefully vetted third-party information technology systems vendors to conduct regular network and endpoint monitoring, vulnerability assessments, and penetration testing. We consider cybersecurity risks associated with our use of third-party information technology vendors during the selection process and include ongoing monitoring as part of our cybersecurity processes. In the year ended December 31, 2023, we did not experience a material “cybersecurity incident,” as such term is defined in Item 106(a) of Regulation S-K.

Chaired by Jonathan Gross, who holds the CERT Certificate in Cybersecurity Oversight from the National Association of Corporate Directors (NACD) and Carnegie Mellon University, the Cybersecurity Committee of the Company’s Board of Directors is responsible for assisting the Board of Directors in fulfilling its oversight responsibilities with respect to (i) cybersecurity risks and (ii) policies and practices to monitor and mitigate cybersecurity risks. The Company’s Board of Directors and its Cybersecurity Committee are briefed regularly on Tellurian’s cybersecurity risks and other cybersecurity-related matters. Additionally, we have established the Cybersecurity Management Committee to provide executive oversight of our cybersecurity risk management processes. The Cybersecurity Management Committee is chaired by Michael Dean, our Chief Information Security Officer (CISO), who has over 30 years of cybersecurity management and information technology leadership experience, and includes our Chief Executive Officer, President, General Counsel and Chief Accounting Officer, among other members of our management team. The Cybersecurity Management Committee holds regular meetings at least quarterly and special meetings as necessary to review identified cybersecurity threat risks or incidences and monitor the operation of our incident response plan. As part of our incident response procedures, our CISO is required to report any identified material cybersecurity incident promptly to our Chief Executive Officer, our President and the Cybersecurity Committee.

ITEM 3. LEGAL PROCEEDINGS

None.

ITEM 4. MINE SAFETY DISCLOSURE

None.

PART II

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

Market Information, Holders and Dividends

Our common stock trades on the NYSE American under the symbol "TELL." As of February 8, 2024, there were 782,393,431 shares outstanding held by 796 record holders of Tellurian's common stock. The Company does not intend to pay cash dividends on its common stock in the foreseeable future.

Recent Sales of Unregistered Securities

None that occurred during the three months ended December 31, 2023.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None that occurred during the three months ended December 31, 2023.

Stock Performance Graph

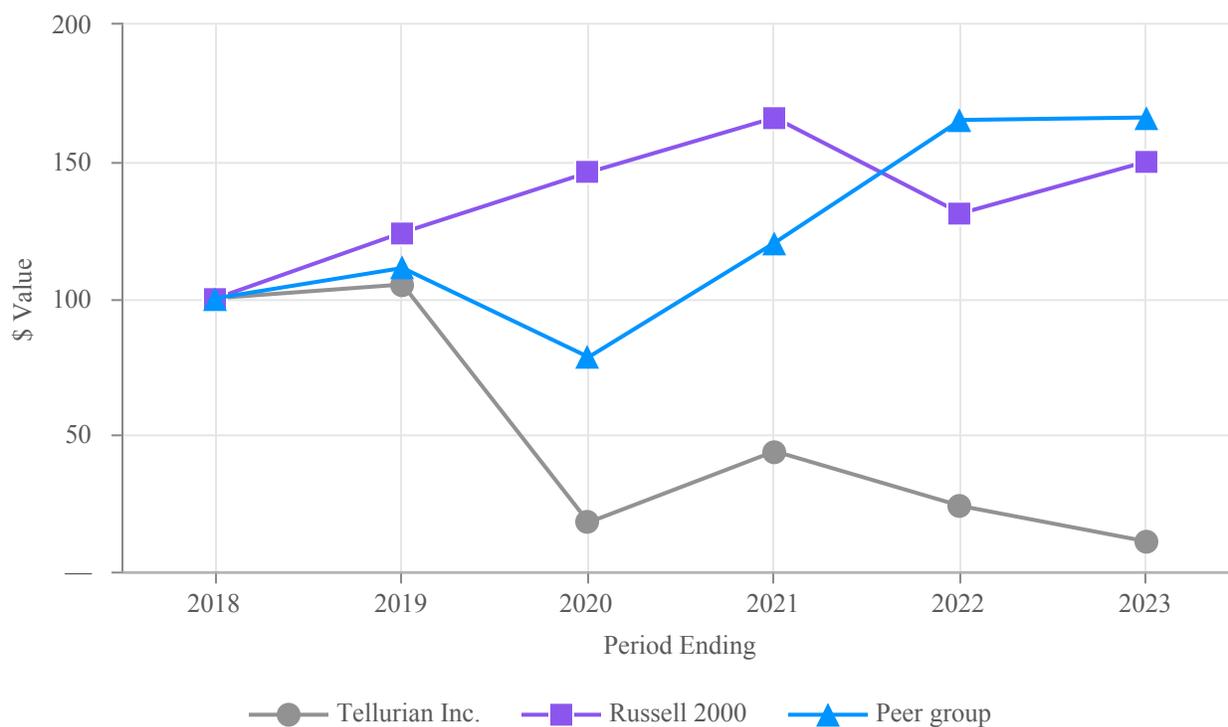
The information contained in this Stock Performance Graph section shall not be deemed to be "soliciting material" or "filed" or incorporated by reference in future filings with the SEC, or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act or the Exchange Act. The following graph compares the cumulative total shareholder return, calculated on a dividend reinvested basis, on \$100.00 invested at the closing of the market on December 31, 2018, through and including the market close on December 31, 2023, with the cumulative total return for the same time period of the same amount invested in the Russell 2000 index and a peer group index. The peer group was selected based on a review of publicly available information about these companies and our determination that they met one or more of the following criteria: (i) comparable industries, (ii) similar market capitalization and (iii) similar operational characteristics, capital intensity, business and operating risks. Our peer group index consists of the following companies:

Peer group

APA Corporation (APA)	NextDecade Corporation (NEXT)
Cheniere Energy, Inc. (LNG)	NuStar Energy L.P. (NS)
Chesapeake Energy Corporation (CHK)	ONEOK, Inc. (OKE)
Comstock Resources, Inc. (CRK)	Range Resources Corporation (RRC)
Enterprise Products Partners L.P. (EPD)	Southwestern Energy Company (SWN)
EQT Corporation (EQT)	Targa Resources Corp. (TRGP)
Gibson Energy Inc. (GEI)	The Williams Companies, Inc. (WMB)
Kinder Morgan, Inc. (KMI)	

	Year Ended December 31,					
	2018	2019	2020	2021	2022	2023
Tellurian Inc.	100	105	18	44	24	11
Russell 2000	100	124	146	166	131	150
Peer group	100	111	78	120	165	166

Stock Performance Graph



ITEM 6. [Reserved]

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

Introduction

The following discussion and analysis presents management's view of our business, financial condition and overall performance and should be read in conjunction with our Consolidated Financial Statements and the accompanying notes. This information is intended to provide investors with an understanding of our past development activities, current financial condition and outlook for the future organized as follows:

- Our Business
- Overview of Significant Events
- Liquidity and Capital Resources
- Capital Development Activities
- Results of Operations
- Commitments and Contingencies
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

Our Business

Tellurian Inc. (“Tellurian,” “we,” “us,” “our,” or the “Company”), a Delaware corporation, is a Houston-based company that is developing and plans to own and operate a portfolio of LNG marketing and infrastructure assets that includes an LNG terminal facility (the “Driftwood terminal”) and related pipelines. The Driftwood terminal and related pipelines are collectively referred to as the “Driftwood Project.” We also own upstream natural gas assets; on February 6, 2024, we announced that we are exploring a sale of those assets. We refer to the Driftwood Project and our upstream assets as the “Business.” As of December 31, 2023, our upstream natural gas assets consist of 30,034 net acres and interests in 161 producing wells located in the Haynesville Shale trend of northern Louisiana. Our Business may be developed in phases.

As part of our execution strategy, which includes increasing our asset base, we will consider various commercial arrangements with third parties across the natural gas value chain. We are also pursuing activities such as direct sales of LNG to global counterparties. We remain focused on the financing and construction of the Driftwood Project.

We manage and report our operations in three reportable segments. The Upstream segment is organized and operates to produce, gather, and deliver natural gas and to acquire and develop natural gas assets. The Midstream segment is organized to develop, construct and operate LNG terminals and pipelines. The Marketing & Trading segment is organized and operates to purchase and sell natural gas produced primarily by the Upstream segment, market the Driftwood terminal’s LNG production capacity and trade LNG.

We continue to evaluate the scope and other aspects of our Business in light of the evolving economic environment, dynamics of the global political landscape, needs of potential counterparties and other factors. How we execute our Business will be based on a variety of factors, including the results of our continuing analysis, changing business conditions and market feedback.

Overview of Significant Events

Driftwood Project Activities

During 2023, we took significant steps to advance construction of the Driftwood terminal making progress on pilings and concrete foundations. We also secured the FERC certificate for certain pipelines and continued to advance the fabrication of long-lead items.

Debt Reductions

During the first quarter of 2023, we repaid a total of approximately \$166.7 million in principal balance of our borrowing obligations.

Debt Refinancing

On August 15, 2023, we issued and sold \$250.0 million aggregate principal amount of 10% Senior Secured Notes due October 1, 2025 (the “Senior Notes”) and approximately \$83.3 million aggregate principal amount of 6% Secured Convertible Notes (the “Convertible Notes”) due October 1, 2025 (collectively the “Replacement Notes”). The issuance of the Replacement Notes resulted in the satisfaction and discharge of the Company’s outstanding principal repayment obligation under the \$500.0 million aggregate principal amount of 6.00% Senior Secured Convertible Notes (the “Extinguished Convertible Notes”).

Upstream Natural Gas Drilling Activities

During the year ended December 31, 2023, we put in production five operated Haynesville wells and participated in nine non-operated Haynesville wells that were put in production.

Liquidity and Capital Resources

Capital Resources

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We are currently funding our operations, development activities and general working capital needs through our cash on hand and the combined proceeds generated by debt and equity issuances, upstream operations and the sale of common stock under our at-the-market equity offering program. We currently maintain an at-the-market equity offering program pursuant to which we may sell our common stock from time to time.

As of December 31, 2023, we had total borrowing obligations of approximately \$391.0 million. The Replacement Notes required us to maintain a minimum cash balance and the holders of the Replacement Notes could redeem up to the entire principal amount of the Replacement Notes if the Company’s liquidity fell below certain minimum liquidity thresholds. See Note 8, *Borrowings*, and Note 19, *Subsequent Events*, of our Notes to the Consolidated Financial Statements for information about the minimum cash balance and the required liquidity thresholds. We also had contractual obligations associated with our finance and operating leases totaling \$391.2 million, of which \$15.2 million is scheduled to be paid within the next twelve

months. Our current capital resources consist of approximately \$75.8 million of cash and cash equivalents and approximately \$25.8 million of accounts receivable.

As of December 31, 2023, the Company has generated losses and cash outflows from operations. We have not yet established an ongoing source of revenues that is sufficient to satisfy our future liquidity thresholds and obligations and fund our working capital needs as they become due during the twelve months following the issuance of the financial statements. These conditions raise substantial doubt about our ability to continue as a going concern.

To date, the Company has been meeting its liquidity needs primarily from cash on hand and the combined proceeds generated by debt and equity issuances, upstream operations, and the sale of common stock under its at-the-market equity offering programs. Our evaluation does not take into consideration the potential mitigating effect of activities that have not been fully implemented or are not within the Company's direct control. Since the issuance of our interim Condensed Consolidated Financial Statements on November 2, 2023, and through the date of this filing, the Company has undertaken the following actions to improve its available cash balances and liquidity:

- From November 2, 2023 to December 31, 2023, raised net proceeds of approximately \$40.2 million from the sale of common stock under our at-the-market equity offering program;
- Subsequent to December 31, 2023, raised net proceeds of approximately \$17.8 million from the sale of common stock under our at-the-market equity offering program (See Note 19, *Subsequent Events*);
- Executed amendments to the Company's Replacement Notes indentures (See Note 19, *Subsequent Events*);
- Initiated a process to explore the sale of our upstream natural gas assets (See Note 19, *Subsequent Events*).
- Identified reductions in the Company's proposed 2024 budget and established a new planning process to manage future general and administrative costs.

Despite these actions, the Company will need to take further measures to generate additional proceeds from various other potential transactions, issuances of equity, equity-linked and debt securities, or similar transactions, managing costs, amending or refinancing the Replacement Notes and offering equity interests in the Driftwood Project (collectively "Management's Plans"). The Company's ability to effectively implement Management's Plans is subject to numerous risks and uncertainties such as a potential inability to sell our upstream assets, market demand for our equity and debt securities, commodity prices and other factors affecting natural gas markets. As of the date of this filing, Management's Plans have not been finalized and are not within the Company's control, and therefore cannot be deemed probable. As a result, there remains substantial doubt about the Company's ability to continue as a going concern. We remain focused on the financing and construction of the Driftwood Project.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash and cash equivalents and costs and expenses for the periods presented (in thousands):

	Year Ended December 31,	
	2023	2022
Cash used in operating activities	\$ (11,189)	\$ (22,534)
Cash used in investing activities	(335,505)	(565,571)
Cash (used in) provided by financing activities	(56,397)	789,299
Net (decrease) increase in cash, cash equivalents and restricted cash	(403,091)	201,194
Cash, cash equivalents and restricted cash, beginning of the period	508,468	307,274
Cash, cash equivalents and restricted cash, end of the period	<u>\$ 105,377</u>	<u>\$ 508,468</u>
Net working capital	<u>\$ (61,668)</u>	<u>\$ 276,750</u>

Cash used in operating activities for the year ended December 31, 2023 decreased by approximately \$11.3 million due primarily to net changes in the Company's working capital from December 31, 2022. See Note 17, *Supplemental Cash Flow Information*, of our Notes to the Consolidated Financial Statements for further information regarding the net changes in the Company's working capital.

Cash used in investing activities for the year ended December 31, 2023 decreased by approximately \$230.1 million compared to 2022. This decrease was primarily due to decreased acquisition and development of natural gas properties of approximately \$113.7 million in the current period, as compared to approximately \$344.8 million in the prior period. See Note 4, *Property, plant and equipment*, of our Notes to the Consolidated Financial Statements for additional information about our investing activities.

Cash (used in) provided by financing activities decreased by approximately \$845.7 million for the year ended December 31, 2023, as compared to 2022. This decrease is primarily due to approximately \$166.7 million in borrowing principal repayments in the current period as compared to \$489.7 million in net proceeds from borrowing issuances in the prior period. The decrease is also due to approximately \$112.1 million in net proceeds from equity issuances as compared to approximately \$299.7 million in the prior period. See Note 8, *Borrowings* and Note 11, *Stockholders' Equity*, of our Notes to the Consolidated Financial Statements for additional information about our financing activities.

Capital Development Activities

The activities we have proposed will require significant amounts of capital and are subject to completion risks and delays. We have received all regulatory approvals for the construction of Phase 1 of the Driftwood terminal and, as a result, our business success will depend to a significant extent upon our ability to obtain the funding necessary to construct assets on a commercially viable basis and to finance the costs of staffing, operating and expanding our company during that process. In March 2022, we issued a limited notice to proceed to Bechtel under our Phase 1 EPC Agreement and commenced the construction of Phase 1 of the Driftwood terminal in April 2022.

We currently estimate the total cost of the Driftwood Project to be approximately \$25.0 billion, including owners' costs, transaction costs and contingencies but excluding interest costs incurred during construction and other financing costs. The proposed Driftwood terminal will have a liquefaction capacity of up to approximately 27.6 Mtpa and will be situated on approximately 1,200 acres in Calcasieu Parish, Louisiana. The proposed Driftwood terminal will include up to 20 liquefaction Trains, three full containment LNG storage tanks and three marine berths.

We anticipate funding our more immediate liquidity requirements for the construction of the Driftwood terminal, natural gas activities, and general and administrative expenses through the use of cash on hand, proceeds from operations, and proceeds from completed and future issuances of securities by us. Investments in the construction of the Driftwood terminal are and will continue to be significant, but the size of those investments will depend on, among other things, commodity prices, Driftwood Project financing developments and other liquidity considerations, and our continuing analysis of strategic risks and opportunities. Consistent with our overall financing strategy, the Company has considered, and in some cases discussed with investors, various potential financing transactions, including issuances of debt, equity and equity-linked securities or similar transactions, to support its capital requirements. The Company will continue to evaluate its cash needs and business outlook, and it may execute one or more transactions of this type in the future.

On February 6, 2024, we announced our intention to explore the sale of our upstream natural gas assets. Decreases in natural gas commodity prices, negative revisions of estimated reserve quantities, increases in future cost estimates or divestitures may lead to a reduction in expected future cash flows of our natural gas reserves and possibly an impairment of our proved natural gas properties in future periods.

As discussed in Note 19, *Subsequent Events*, to our Consolidated Financial Statements, we amended certain terms of the indentures governing the Replacement Notes on February 22, 2024. As part of the February transaction, we provided a non-recourse pledge of our equity interests in a subsidiary that indirectly owns the principal properties comprising the Driftwood Project. The non-recourse pledge will be released upon the redemption or repayment of the Senior Notes. We do not expect the existence of this pledge to interfere with any aspect of the commercialization or financing of the Driftwood Project. Further, we expect that our improved near-term liquidity resulting from the transaction will enable a higher degree of engagement with potential counterparties and financing sources for the project.

Results of Operations

The following table summarizes revenues, costs and expenses for the periods presented (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Natural gas sales	\$ 166,128	\$ 270,975	\$ 51,499
LNG sales	—	120,951	19,776
Total revenue	166,128	391,926	71,275
Operating expenses	78,186	37,886	11,693
LNG cost of sales	—	131,663	24,745
Total cost of sales	78,186	169,549	36,438
Development expenses	35,616	68,782	50,186
Depreciation, depletion and amortization	98,426	44,357	11,481
General and administrative expenses	101,902	126,386	85,903
Related party charges	660	625	—
Loss from operations	(148,662)	(17,773)	(112,733)
Interest expense, net	(18,047)	(13,860)	(9,378)
(Loss) gain on extinguishment of debt, net	(32,295)	—	1,422
Other income (expense), net	32,827	(18,177)	5,951
Income tax benefit (provision)	—	—	—
Net loss	\$ (166,177)	\$ (49,810)	(114,738)

The most significant changes affecting our results of operations for the year ended December 31, 2023 compared to 2022, on a consolidated basis and by segment, are the following:

Upstream

- Decrease of approximately \$104.8 million in Natural gas sales as a result of lower realized natural gas prices partially offset by increased production volumes attributable to the acquisition of proved natural gas properties in 2022 and newly drilled and completed wells during 2023 and 2022.
- Increase of approximately \$40.3 million in Operating expenses as a result of higher production volumes and approximately \$7.6 million of natural gas drilling rig standby costs incurred during the current period.
- Increase of approximately \$54.1 million in DD&A primarily attributable to a higher asset net book value utilized in the calculation of DD&A due to the acquisition of natural gas properties in 2022, capital expenditures during 2022 and 2023 and increased natural gas production volumes during the current period.

Marketing & Trading

- Decrease of approximately \$121.0 million and approximately \$131.7 million in LNG sales and LNG cost of sales, respectively, due to the absence of an LNG cargo sale during the current period.

Midstream

- Decrease of approximately \$33.2 million in Development expenses primarily attributable to the capitalization of directly identifiable Driftwood Project costs as construction in progress during the current period which were expensed in the prior period and \$6.2 million in the cost of land and roads donated for public use in the state of Louisiana in the prior period.

Consolidated

- Decrease of approximately \$24.5 million in General and administrative expenses primarily attributable to decreased compensation expenses in the current period and the accrual of a \$9.0 million donation to a university for global energy research in the prior period.
- Increase of approximately \$32.3 million in Loss on extinguishment of debt, net due primarily to the extinguishment of the Company's Extinguished Convertible Notes and issuance of the Replacement Notes, which resulted in a loss of approximately \$29.5 million in the current period.

- Increase of approximately \$51.0 million in Other income (expense), net primarily attributable to approximately \$23.3 million of realized gains on the settlement of natural gas financial instruments, \$17.0 million of unrealized gain due to changes in the fair value of the Embedded derivative liability and \$10.5 million of unrealized loss on natural gas financial instruments during the current period as compared to \$27.2 million of realized loss and \$10.5 million of unrealized gain on natural gas financial instruments in the prior period.

As a result of the foregoing, our consolidated Net loss was approximately \$166.2 million for the year ended December 31, 2023, compared to a Net loss of approximately \$49.8 million in 2022.

The most significant changes affecting our results of operations for the year ended December 31, 2022 compared to 2021, on a consolidated basis and by segment, are the following:

Upstream

- Increase of approximately \$219.5 million and approximately \$26.2 million in Natural gas sales and Operating expenses, respectively, attributable to increased realized natural gas prices and production volumes, as compared to 2021.
- Increase of approximately \$32.9 million in DD&A is primarily attributable to a higher net book value utilized in the calculation of DD&A due to the acquisition of proved natural gas assets, increased capital expenditures and higher production volumes, as compared to 2021.

Marketing & Trading

- Increase of approximately \$101.2 million and approximately \$106.9 million in LNG sales and LNG cost of sales, respectively, primarily as a result of increased realized sales and purchase prices of an LNG cargo sold during the first quarter of 2022, as compared to the realized price of an LNG cargo sold during the second quarter of 2021.
- Decrease of approximately \$24.1 million in Other income (expense), net primarily attributable to approximately \$27.2 million of realized losses on the settlement of natural gas financial instruments, which was partially offset by a \$10.5 million unrealized gain on natural gas financial instruments due to changes in the fair value of the Company's derivative instruments during 2022 as compared to 2021. The net loss on natural gas financial instruments in the current period was partially offset by approximately \$3.5 million of realized gain on the settlements of LNG financial instruments.

Midstream

- Increase of approximately \$18.6 million in Development expenses primarily attributable to a one-time donation of \$6.8 million of land and roads for public use in the state of Louisiana, an approximately \$3.1 million increase in technical and engineering services, and an approximately \$8.7 million increase in other development expenses, as compared to 2021.

Consolidated

- Increase of approximately \$40.5 million in General and administrative expenses primarily attributable to a \$14.6 million increase in professional services, a \$9.0 million increase in donations to a university to advance global energy research and an increase of \$16.9 million in other expenses, as compared to 2021.
- Increase of approximately \$4.5 million in Interest expense, net due to increased interest charges as a result of the Company's increase in borrowing obligations during 2022 as compared to 2021. The increase in Interest expense, net was partially offset by approximately \$5.7 million of capitalized interest during 2022. For further information regarding the Company's outstanding borrowing obligations, see Note 8, *Borrowings*, of our Notes to the Consolidated Financial Statements.

As a result of the foregoing, our consolidated Net loss was approximately \$49.8 million for the year ended December 31, 2022, compared to a Net loss of approximately \$114.7 million in 2021.

Commitments and Contingencies

The information set forth in Note 10, *Commitments and Contingencies*, to the accompanying Consolidated Financial Statements included in Part II, Item 8 of this Form 10-K is incorporated herein by reference.

Summary of Critical Accounting Estimates

Our accounting policies are more fully described in Note 2, *Summary of Significant Accounting Policies*, of our Notes to Consolidated Financial Statements included in this report. As disclosed in Note 2, the preparation of financial statements requires the use of judgments and estimates. We base our estimates on historical experience and on various other assumptions we believe to be reasonable according to 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. Actual results could differ from these estimates. We considered the following to be our most critical accounting estimates that involve significant judgment:

Valuation of Long-Lived Assets

When there are indicators that our proved natural gas properties carrying value may not be recoverable, we compare expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on our estimates of (and assumptions regarding) future natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the income approach in accordance with GAAP. Estimates of undiscounted future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation. In addition, such assumptions and estimates are reasonably likely to change in the future.

Proved reserves are the estimated quantities of natural gas and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, because we use the units-of-production method to deplete our natural gas properties, the quantity of reserves could significantly impact our DD&A expense. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Finally, these reserves are the basis for our supplemental natural gas disclosures. See Item 1 and 2 — *Our Business and Properties* for additional information on our estimate of proved reserves.

Share-Based Compensation

Share-based compensation transactions are measured based on the grant-date estimated fair value. For awards containing only service conditions or performance conditions deemed probable of occurring, the fair value is recognized as expense over the requisite service period using the straight-line method. We recognize compensation cost for awards with performance conditions if and when we conclude that it is probable that the performance condition will be achieved. For awards where the performance or market condition is not considered probable, compensation cost is not recognized until the performance or market condition becomes probable. We reassess the probability of vesting at each reporting period for awards with performance conditions and adjust compensation cost based on our probability assessment. We recognize forfeitures as they occur.

Recent Accounting Standards

We do not believe that any recently issued, but not yet effective, accounting standards, if currently adopted, would have a material effect on our Consolidated Financial Statements or related disclosures.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary market risk relating to our financial instruments is the volatility in market prices for our natural gas production. As of December 31, 2023, there were no open natural gas financial instrument positions. Accordingly, we do not believe that we hold, or are party to, instruments that are subject to market risks that are material to our Business. Refer to Note 9, *Financial Instruments*, of the consolidated financial statements included in this Annual Report for additional details about our financial instruments and their fair value.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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TELLURIAN INC.**

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Company's Chief Executive Officer, President, Chief Financial Officer, and Chief Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Tellurian Inc.'s internal control over financial reporting was effective as of December 31, 2023.

Deloitte & Touche LLP, an independent registered public accounting firm, audited the effectiveness of Tellurian Inc.'s internal control over financial reporting as of December 31, 2023, as stated in their report on page 44.

<u>/s/ Octávio M.C. Simões</u>	<u>/s/ Daniel A. Belhumeur</u>	<u>/s/ Simon G. Oxley</u>	<u>/s/ Khaled A. Sharafeldin</u>
Octávio M.C. Simões	Daniel A. Belhumeur	Simon G. Oxley	Khaled A. Sharafeldin
<i>Chief Executive Officer (as co-Principal Executive Officer)</i>	<i>President (as co-Principal Executive Officer)</i>	<i>Chief Financial Officer (as Principal Financial Officer)</i>	<i>Chief Accounting Officer (as Principal Accounting Officer)</i>

Houston, Texas

February 23, 2024

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Tellurian Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Tellurian Inc. and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

We have also 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, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2024, expressed an unqualified opinion on the Company's internal control over financial reporting.

Going Concern

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has incurred recurring losses from operations and has yet to establish an ongoing source of revenues that is sufficient to cover its future operating costs and obligations as they become due for the twelve months following the date these consolidated financial statements are issued, which raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

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 Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Proved Natural Gas Properties and Depletion – Natural Gas Reserves — Refer to Notes 2 and 4 to the financial statements

Critical Audit Matter Description

The Company's proved natural gas properties are depleted using the units-of-production method based upon natural gas reserves. The development of the Company's natural gas reserve quantities requires management to make significant estimates and assumptions. The Company engages an independent reservoir engineer, management's specialist, to estimate natural gas quantities using generally accepted methods, calculation procedures and engineering data. Changes in assumptions or engineering data could have a significant impact on the amount of depletion.

Given the significant judgments made by management and management's specialist, performing audit procedures to evaluate the Company's natural gas reserve quantities, including management's estimates and assumptions related to the natural gas prices, production volumes and capital expenditures required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to natural gas reserves included the following, among others:

- We tested the effectiveness of controls related to the Company's estimation of natural gas properties reserves quantities, including controls relating to the natural gas prices.
- We evaluated the reasonableness of natural gas prices by comparing such amounts to:
 - Third party industry sources.
 - Historical realized natural gas prices.
 - Historical realized natural gas price differentials.
- We evaluated the Company's estimates for production volumes by evaluating wells' past production performance to determine whether it was appropriately reflected in production forecasts used in generating proved reserves.
- We evaluated the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm, including the methodologies and calculation procedures used to estimate natural gas reserves and performing analytical procedures on the reserve quantities.

Upstream natural gas properties, net - Determination of Impairment Indicators and Recoverability Test – Refer to Notes 2 and 4 to the financial statements

Critical Audit Matter Description

Management tests property, plant and equipment for impairment whenever there are indicators that the carrying amount of property, plant and equipment might not be recoverable. The carrying values of the Company's proved natural gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. If there is an indication that the carrying amount of our proved natural gas properties may not be recoverable, management compares the estimated undiscounted future cash flows from natural gas properties to the carrying values of those properties. Proved natural gas properties that have carrying amounts in excess of estimated undiscounted cash flows are written down to fair value.

We have identified the determination of impairment indicators for proved natural gas properties as a critical audit matter due to the significant judgments management makes when determining whether events or changes in circumstances have occurred indicating that the carrying amounts of the properties may not be recoverable. We have also identified elements of the Company's recoverability test for proved natural gas properties as a critical audit matter due to the significant judgments management makes when determining future cash flows. Auditing management's judgments related to these matters involved especially challenging auditor judgment due to the nature and extent of audit effort required, including the need to involve our fair value specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to the determination of impairment indicators and elements of the Company's recoverability analysis for proved natural gas properties included the following, among others:

- We evaluated management's analysis of impairment indicators by:
 - Testing the effectiveness of Company's impairment controls.
 - Assessing whether proved natural gas properties having indicators of impairment were appropriately identified.
- We obtained the recoverability test analysis including the estimation of natural gas properties reserves quantities:
 - We tested the effectiveness of controls related to the Company's recoverability test analysis and its estimation of proved natural gas properties reserve quantities, including controls relating to the natural gas prices.
 - We evaluated the reasonableness of future capital expenditures by comparing to historical wells drilled.

- With the assistance of our fair value specialists, we assessed the key assumptions and estimates, including natural gas prices and risk factors by:
 - Understanding the methodology used by management for development of the natural gas prices and comparing the estimated prices to an independently determined range of prices, including published forward pricing indices and third-party industry sources.
 - Evaluating the risk factors applied to the cash flows for probable and possible natural gas reserves by comparing to industry surveys.
- We assessed the probability weighting of management’s cash flow scenarios.
- We evaluated the experience, qualifications and objectivity of management’s specialist, an independent reservoir engineering firm, including the methodologies and calculation procedures used to estimate natural gas reserves and performing analytical procedures on the reserve quantities.

Embedded features in the Replacement Notes and Valuation of Derivatives— Refer to Notes 2, 7, 8 and 9 to the financial statements

Critical Audit Matter Description

During 2023, the Company issued and sold \$250.0 million of 10% Senior Notes due October 2025 and \$83.3 million of 6% Senior Convertible Notes due October 2025 (collectively, the “Replacement Notes”). The issuance of the Replacement Notes to the holder of the Extinguished Convertible Notes resulted in the satisfaction and discharge of the Company’s outstanding principal repayment obligation under the Extinguished Convertible Notes due May 2025. The Company evaluated the potential embedded features within the Replacement Notes host contracts and determined that the Convertible Feature, Share Coupon, the Cash Shortfall Payments and the Make Whole embedded features required bifurcation as a single unit of account from the Replacement Notes and accounted for them separately at fair value.

Given the complexity of accounting for embedded features in the Replacement Notes and the degree of judgment involved in valuation of the embedded derivatives, auditing the related accounting conclusions and valuation involved significant auditor judgment and an increased extent of effort, including the use of our fair value specialists and professionals in our firm with expertise in financial instruments.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management’s significant judgments and assumptions related to embedded derivatives in the Replacement Notes host contracts included the following, among others:

- We read the Replacement Notes agreements to understand the terms and conditions, economic substance and embedded features requiring evaluation.
- With the assistance of professionals in our firm with expertise in financial instruments, we evaluated management’s analysis of each embedded feature and the application of the relevant accounting guidance to assess if the embedded features require recognition as separate derivative financial instruments.
- We obtained an understanding of management’s process for developing the estimated fair value, including understanding the method applied. Further, with the assistance of our fair value specialists, we evaluated the significant assumptions and methodology used in developing the fair value estimates, including:
 - Evaluating management’s estimation related to stock price, risk-free rate, discount rate and dividend yield.
 - Comparing the forecasted volatility of the Company’s common stock price to its historical volatility.
 - Evaluating management’s methodologies including discounted cash flow model, Black-Scholes-Merton Model and Monte Carlo Simulation.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 23, 2024

We have served as the Company’s auditor since 2016.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Tellurian Inc.

Opinions on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Tellurian Inc. and subsidiaries (the "Company") as of December 31, 2023, based on criteria established in *Internal Control – Integrated Framework (2013)* 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, 2023, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2023, of the Company and our report dated February 23, 2024, 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 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/ DELOITTE & TOUCHE LLP

Houston, Texas

February 23, 2024

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share amounts)

	December 31,	
	2023	2022
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 75,789	\$ 474,205
Accounts receivable	25,790	76,731
Prepaid expenses and other current assets	15,951	23,355
Total current assets	117,530	574,291
Property, plant and equipment, net	1,136,299	789,076
Other non-current assets	70,199	63,316
Total assets	<u>\$ 1,324,028</u>	<u>\$ 1,426,683</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 55,548	\$ 4,805
Accrued and other liabilities	123,650	129,180
Borrowings	—	163,556
Total current liabilities	179,198	297,541
Long-term liabilities:		
Borrowings	361,402	382,208
Finance lease liabilities	121,450	49,963
Other non-current liabilities	37,054	24,428
Total long-term liabilities	519,906	456,599
Commitments and Contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, \$0.01 par value, 100,000,000 shares authorized: 6,123,782 and 6,123,782 shares outstanding, respectively	61	61
Common stock, \$0.01 par value, 1,600,000,000 and 800,000,000 shares authorized: 703,739,585 and 564,567,568 shares outstanding, respectively	6,866	5,456
Additional paid-in capital	1,765,044	1,647,896
Accumulated deficit	(1,147,047)	(980,870)
Total stockholders' equity	624,924	672,543
Total liabilities and stockholders' equity	<u>\$ 1,324,028</u>	<u>\$ 1,426,683</u>

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

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2023	2022	2021
Revenues:			
Natural gas sales	\$ 166,128	\$ 270,975	\$ 51,499
LNG sales	—	120,951	19,776
Total revenue	<u>166,128</u>	<u>391,926</u>	<u>71,275</u>
Operating costs and expenses:			
LNG cost of sales	—	131,663	24,745
Operating expenses	78,186	37,886	11,693
Development expenses	35,616	68,782	50,186
Depreciation, depletion and amortization	98,426	44,357	11,481
General and administrative expenses	101,902	126,386	85,903
Related party charges (Note 6)	660	625	—
Total operating costs and expenses	<u>314,790</u>	<u>409,699</u>	<u>184,008</u>
Loss from operations	(148,662)	(17,773)	(112,733)
Interest expense, net	(18,047)	(13,860)	(9,378)
(Loss) gain on extinguishment of debt, net	(32,295)	—	1,422
Other income (expense), net	<u>32,827</u>	<u>(18,177)</u>	<u>5,951</u>
Loss before income taxes	(166,177)	(49,810)	(114,738)
Income tax benefit (provision)	—	—	—
Net loss	<u>\$ (166,177)</u>	<u>\$ (49,810)</u>	<u>\$ (114,738)</u>
Net loss per common share:			
Basic and diluted	<u>\$ (0.29)</u>	<u>\$ (0.09)</u>	<u>\$ (0.28)</u>
Weighted average shares outstanding:			
Basic and diluted	<u>565,678</u>	<u>526,946</u>	<u>407,615</u>

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

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(in thousands)

	Year Ended December 31,		
	2023	2022	2021
Total shareholders' equity, beginning balance	\$ 672,543	\$ 418,301	\$ 109,090
Preferred stock	61	61	61
Common stock:			
Beginning balance	5,456	4,774	3,309
Common stock issuance	1,407	677	1,361
Share-based compensation, net	3	3	43
Share-based payments	—	2	1
Warrants exercised	—	—	60
Ending balance	<u>6,866</u>	<u>5,456</u>	<u>4,774</u>
Additional paid-in capital:			
Beginning balance	1,647,896	1,344,526	922,042
Common stock issuance	115,614	299,063	406,493
Share-based compensation, net	1,534	3,631	7,892
Share-based payments	—	676	200
Warrants exercised	—	—	8,117
Debt extinguishment	—	—	(218)
Ending balance	<u>1,765,044</u>	<u>1,647,896</u>	<u>1,344,526</u>
Accumulated deficit:			
Beginning balance	(980,870)	(931,060)	(816,322)
Net loss	(166,177)	(49,810)	(114,738)
Ending balance	<u>(1,147,047)</u>	<u>(980,870)</u>	<u>(931,060)</u>
Total shareholders' equity, ending balance	<u>\$ 624,924</u>	<u>\$ 672,543</u>	<u>\$ 418,301</u>

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

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	<u>Year Ended December 31,</u>		
	<u>2023</u>	<u>2022</u>	<u>2021</u>
Cash flows from operating activities:			
Net loss	\$ (166,177)	\$ (49,810)	\$ (114,738)
Adjustments to reconcile Net loss to Net cash used in operating activities:			
Depreciation, depletion and amortization	98,426	44,357	11,481
Amortization of debt issuance costs, discounts and fees	7,111	2,424	3,102
Share-based compensation	1,537	3,633	5,950
Share-based payments	—	678	200
Interest elected to be paid-in-kind	—	—	508
Loss (gain) on financial instruments not designated as hedges	10,346	(9,073)	(8,693)
Change in fair value of Embedded derivative	(18,594)	—	—
Loss (gain) on extinguishment of debt, net	32,295	—	(1,422)
Other	2,977	1,210	1,035
Net changes in working capital (Note 17)	20,890	(15,953)	41,017
Net cash used in operating activities	<u>(11,189)</u>	<u>(22,534)</u>	<u>(61,560)</u>
Cash flows from investing activities:			
Acquisition and development of natural gas properties	(113,653)	(344,800)	(32,364)
Driftwood Project construction costs	(200,127)	(175,791)	(15,208)
Land purchases and land improvements	—	(23,492)	(10,293)
Investment in unconsolidated entity	—	(6,089)	—
Note receivable	(18,000)	(6,595)	—
Capitalized internal use software and other assets	(3,725)	(8,804)	—
Net cash used in investing activities	<u>(335,505)</u>	<u>(565,571)</u>	<u>(57,865)</u>
Cash flows from financing activities:			
Proceeds from common stock issuances	115,612	309,021	421,809
Equity issuance costs	(3,489)	(9,281)	(13,955)
Borrowing proceeds	—	501,178	56,500
Borrowing issuance costs	—	(11,487)	(2,854)
Borrowing principal repayments	(166,666)	—	(119,725)
Proceeds from warrant exercise	—	—	8,177
Tax payments for net share settlements of equity awards (Note 17)	—	—	(3,064)
Other	(1,854)	(132)	(1,926)
Net cash (used in) provided by financing activities	<u>(56,397)</u>	<u>789,299</u>	<u>344,962</u>
Net (decrease) increase in cash, cash equivalents and restricted cash	(403,091)	201,194	225,537
Cash, cash equivalents and restricted cash, beginning of period	508,468	307,274	81,737
Cash, cash equivalents and restricted cash, end of period	<u>105,377</u>	<u>508,468</u>	<u>307,274</u>
Supplementary disclosure of cash flow information:			
Interest paid, net of capitalized interest	\$ 14,203	\$ 20,647	\$ 4,105

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

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — ORGANIZATION AND NATURE OF OPERATIONS

Tellurian Inc. (“Tellurian,” “we,” “us,” “our,” or the “Company”), a Delaware corporation, is a Houston-based company that is developing and plans to own and operate a portfolio of LNG marketing and infrastructure assets that includes an LNG terminal facility (the “Driftwood terminal”) and related pipelines. The Driftwood terminal and related pipelines are collectively referred to as the “Driftwood Project.” We also own upstream natural gas assets. On February 6, 2024, we announced that we are exploring a sale of those assets. See Note 19, *Subsequent Events*, for further information. We refer to the Driftwood Project and our upstream assets collectively as the “Business.”

The terms “we,” “our,” “us,” “Tellurian” and the “Company” as used in this report refer collectively to Tellurian Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity associated with Tellurian Inc.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements have been prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of Tellurian Inc. and its wholly owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications did not have a material effect on our consolidated financial position, results of operations or cash flows.

Going Concern

Our Consolidated Financial Statements have been prepared in accordance with GAAP, which contemplates the realization of assets and satisfaction of liabilities in the normal course of business as well as the Company’s ability to continue as a going concern. In accordance with ASC Subtopic 205-40, *Presentation of Financial Statements—Going Concern*, the Company evaluates whether conditions and/or events raise substantial doubt about its ability to meet its obligations as they become due within one year after the date that the financial statements are issued. As of December 31, 2023, the Company has generated losses and cash outflows from operations. We have not yet established an ongoing source of revenues that is sufficient to satisfy our future liquidity thresholds and obligations and fund our working capital needs as they become due during the twelve months following the issuance of the financial statements. These conditions raise substantial doubt about our ability to continue as a going concern.

To date, the Company has been meeting its liquidity needs primarily from cash on hand and the combined proceeds generated by debt and equity issuances, upstream operations, and the sale of common stock under its at-the-market equity offering programs. Our evaluation does not take into consideration the potential mitigating effect of activities that have not been fully implemented or are not within the Company’s direct control. Since the issuance of our interim Condensed Consolidated Financial Statements on November 2, 2023, and through the date of this filing, the Company has undertaken the following actions to improve its available cash balances and liquidity:

- From November 2, 2023 to December 31, 2023, raised net proceeds of approximately \$40.2 million from the sale of common stock under our at-the-market equity offering program;
- Subsequent to December 31, 2023, raised net proceeds of approximately \$17.8 million from the sale of common stock under our at-the-market equity offering program (See Note 19, *Subsequent Events*);
- Executed amendments to the Company’s Replacement Notes indentures (See Note 19, *Subsequent Events*);
- Initiated a process to explore the sale of our upstream natural gas assets (See Note 19, *Subsequent Events*).

Despite these actions, the Company will need to take further measures to generate additional proceeds from various other potential transactions, such as issuances of equity, equity-linked and debt securities, or similar transactions, managing costs, amending or refinancing the Replacement Notes and offering equity interests in the Driftwood Project (collectively “Management’s Plans”). The Company’s ability to effectively implement Management’s Plans is subject to numerous risks and uncertainties such as a potential inability to sell our upstream assets, market demand for our equity and debt securities, commodity prices and other factors affecting natural gas markets. As of the date of this filing, Management’s Plans have not been finalized and are not within the Company’s control and, therefore, cannot be deemed probable. As a result, there remains substantial doubt about the Company’s ability to continue as a going concern.

The Consolidated Financial Statements do not include any adjustments to the carrying amounts and classification of assets, liabilities, and reported expenses that may be necessary if the Company were unable to continue as a going concern.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Segments

Segment information is prepared on the same basis that our Chief Operating Decision Maker, uses to manage the segments, evaluate financial results and make key operating decisions. We identified the Upstream, Midstream and Marketing & Trading components as the Company's operating segments. These operating segments represent the Company's reportable segments. The remainder of our business is presented as "Corporate," and consists of corporate costs and intersegment eliminations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and the accompanying notes. Management evaluates its estimates and related assumptions on a regular basis. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company uses three levels of the fair value hierarchy of inputs to measure the fair value of an asset or a liability. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Level 3 inputs are inputs that are not observable in the market.

Revenue Recognition

For the sale of natural gas, we consider the delivery of each unit (MMBtu) to be a separate performance obligation that is satisfied upon delivery to the designated sales point and therefore is recognized at a point in time. These contracts are either fixed price contracts or contracts with a fixed differential to an index price, both of which are deemed fixed consideration that is allocated to each performance obligation and represents the relative standalone selling price basis.

Each LNG cargo, in its entirety, is deemed to be a single performance obligation due to each molecule of LNG being distinct and substantially the same and therefore meeting the criteria for the transfer of a series of distinct goods. Accordingly, LNG sales are recognized at a point in time when the LNG has completed discharging to the customer. These are contracts with a fixed differential to an index price, which is deemed fixed consideration that is allocated to each performance obligation and represents the relative standalone selling price basis. These LNG sales are recorded on a gross basis and reported in "LNG sales" on the Consolidated Statements of Operations.

Purchases and sales of LNG inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in "LNG sales" on the Consolidated Statements of Operations. For such LNG sales, we require payment within 10 days from delivery. We exclude all taxes from the measurement of the transaction price.

Receivables

The Company's accounts receivable consist primarily of trade receivables from natural gas sales and joint interest billings due from owners on properties the Company operates. The majority of these receivables have payment terms of 30 days or less. The Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings for receivables due from joint interest owners. We evaluate expected credit losses on our receivables based on relevant information about past events, including historical experience and other relevant conditions which may impact their carrying value. The Company's historical credit losses have been de minimis and are expected to remain so in the future assuming no substantial changes to the business or creditworthiness of the Company's counterparties.

Cash, Cash Equivalents and Restricted Cash

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents that are restricted as to withdrawal or use under the terms of certain contractual agreements are recorded as restricted cash on our Consolidated Balance Sheets. The carrying value of cash, cash equivalents and restricted cash approximates their fair value.

Concentration of Cash

We maintain cash balances and restricted cash at financial institutions, which may, at times, be in excess of federally insured levels. We have not incurred losses related to these balances to date.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivative Instruments

We may use derivative instruments to hedge our exposure to cash flow variability from commodity price risk. Derivative instruments are recorded at fair value and included in our Consolidated Balance Sheets as assets or liabilities, depending on the derivative position and the expected timing of settlement, unless they satisfy the criteria for and we elect the normal purchases and sales exception.

We have not elected and do not apply hedge accounting for our derivative instruments; therefore, all changes in fair value of the Company's derivative instruments are recognized within Other income, net, in the Consolidated Statements of Operations. Settlements of derivative instruments are reported as a component of cash flows from operations in the Consolidated Statements of Cash Flows.

Property, Plant and Equipment

Natural gas development and production activities are accounted for using the successful efforts method of accounting. Costs incurred to acquire a property (whether proved or unproved) are capitalized when incurred. Costs to develop proved reserves are capitalized and our natural gas reserves are depleted using the units-of-production method.

Fixed assets are recorded at cost. We depreciate our property, plant and equipment, excluding land, using the straight-line depreciation method over the estimated useful life of the asset. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed, and the resulting gains or losses are recorded in our Consolidated Statements of Operations.

Management tests property, plant and equipment for impairment whenever there are indicators that the carrying amount of property, plant and equipment might not be recoverable. The carrying values of our proved natural gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. If there is an indication that the carrying amount of our proved natural gas properties may not be recoverable, we compare the estimated probability-weighted undiscounted future cash flows from our natural gas properties to the carrying values of those properties. Proved properties that have carrying amounts in excess of estimated undiscounted cash flows are written down to fair value.

Leases

The Company determines if an arrangement is a lease at inception. Leases are recognized as either finance or operating leases on our Consolidated Balance Sheets by recording a lease liability representing the obligation to make future lease payments and a right-of-use asset representing the right to use the underlying asset for the lease term. We combine lease and non-lease components of an arrangement for all classes of our leased assets and omit short-term leases with a term of 12 months or less from recognition on the balance sheet. In the absence of a readily determinable implicit interest rate, we discount our expected future lease payments using our incremental borrowing rate. Options to renew a lease are included in the lease term and recognized as part of the right-of-use asset and lease liability, only to the extent they are reasonably certain to be exercised.

Lease expense for operating lease payments is recognized on a straight-line basis over the lease term. Lease expense for finance leases is recognized as the sum of the amortization of the right-of-use assets on a straight-line basis and the interest on lease liabilities over the lease term.

Accounting for LNG Development Activities

During the preliminary stage of developing the Driftwood terminal, substantially all the costs related to such activities have been expensed. These costs primarily included professional fees associated with FEED studies and complying with FERC for authorization to construct our terminal and other required permitting for the Driftwood Project.

Costs incurred in connection with a project to develop the Driftwood terminal shall generally be treated as development expenses until the project has reached the notice-to-proceed state ("NTP State") and the following criteria (the "NTP Criteria") have been met: (i) the necessary regulatory permits have been obtained, (ii) financing for the project has been secured and (iii) management has committed to commence construction.

In addition, certain costs incurred prior to achieving the NTP State will be capitalized although the NTP Criteria have not been met. Costs to be capitalized prior to achieving the NTP State include land purchase costs, land improvement costs, costs associated with preparing the facility for use, direct payroll and payroll benefit-related costs and any fixed structure construction costs (fence, storage areas, drainage, etc.). Furthermore, activities directly associated with detailed engineering and/or facility designs shall be capitalized. Interest is capitalized in connection with the construction of major facilities. All amounts capitalized are periodically assessed for impairment and may be impaired if indicators are present.

Prior to reaching the NTP State, costs incurred to complete construction activities necessary to proceed under our LSTK EPC agreement with Bechtel are capitalized as construction in progress when the following criteria are met: (i) costs

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

incurred are directly identifiable, (ii) necessary regulatory permits are secured, (iii) funding for the scope of work is available, and (iv) construction activities are creditable under the LSTK EPC agreement.

Prior to reaching the NTP State, costs incurred to complete construction activities necessary to develop the Driftwood pipelines are capitalized as construction in progress when the following criteria are met: (i) costs incurred are directly identifiable, (ii) necessary regulatory permits are secured, and (iii) funding for the scope of work is available.

Debt

Discounts, premiums, fees and expenses incurred with the issuance of debt are amortized over the term of the debt. These amounts are presented net of our indebtedness balances on the accompanying Consolidated Balance Sheets. We evaluate embedded features within a debt host contract to determine whether there are embedded derivatives that should be bifurcated and carried separately at fair value.

Embedded derivatives that are not clearly and closely related to the host contract are bifurcated and recorded at fair value with subsequent changes in fair value recorded in the Consolidated Statements of Operations.

Share-Based Compensation

We have awarded share-based compensation in the form of stock, restricted stock, restricted stock units and stock options to employees, directors and outside consultants. Share-based compensation transactions are measured based on the grant-date estimated fair value. For awards containing only service conditions or performance conditions deemed probable of occurring, the fair value is recognized as expense over the requisite service period using the straight-line method. We recognize compensation cost for awards with performance conditions if and when we conclude that it is probable that the performance condition will be achieved. For awards where the performance or market condition is not considered probable, compensation cost is not recognized until the performance or market condition becomes probable. We reassess the probability of vesting at each reporting period for awards with performance conditions and adjust compensation cost based on our probability assessment. We recognize forfeitures as they occur.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, we determine deferred tax assets and liabilities on the basis of the differences between the financial statement and tax basis of assets and liabilities by using enacted tax rates in effect for the year in which the differences are expected to be realized or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

We recognize deferred tax assets to the extent that we believe that these assets are more likely than not to be realized. In making such a determination, we consider current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. If we determine that we would be able to realize our deferred tax assets in the future in excess of their net recorded amount, we will make an adjustment to the deferred tax asset valuation allowance, which would reduce the provision for income taxes.

Post employment benefits

The Company provides cash and other termination benefits pursuant to ongoing benefit arrangements to its employees in connection with a qualifying termination of their employment. The cost of providing post employment benefits is recognized when the obligation is probable of occurring and can be reasonably estimated.

Net Loss Per Share

Basic net loss per share excludes dilution and is computed by dividing net loss by the weighted average number of common shares outstanding during the period. Diluted net loss per share reflects potential dilution and is computed by dividing net loss by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued and were dilutive.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3 — PREPAID EXPENSES AND OTHER CURRENT ASSETS

Prepaid expenses and other current assets consist of the following (in thousands):

	December 31,	
	2023	2022
Prepaid expenses	\$ 1,788	\$ 2,174
Restricted cash	4,688	9,375
Derivative asset, net - current (Note 9)	—	10,463
Upstream pipe	4,278	978
Deposits and other current assets	5,197	365
Total prepaid expenses and other current assets	\$ 15,951	\$ 23,355

Restricted Cash

Restricted cash as of December 31, 2023 and December 31, 2022 represents cash held in escrow under the terms of the purchase and sale agreement for the acquisition of certain natural gas assets in the Haynesville Shale. See Note 4, *Property, Plant and Equipment*, for further information.

NOTE 4 — PROPERTY, PLANT AND EQUIPMENT

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

	December 31,	
	2023	2022
Upstream natural gas assets:		
Proved properties	\$ 492,506	\$ 412,977
Wells in progress	68,797	55,374
Accumulated DD&A	(187,171)	(92,423)
Total upstream natural gas assets, net	374,132	375,928
Driftwood Project assets:		
Terminal construction in progress	533,316	292,734
Pipeline construction in progress	35,939	—
Land and land improvements	53,664	52,460
Finance lease assets, net of accumulated DD&A	55,534	56,708
Buildings and other assets, net of accumulated DD&A	310	340
Total Driftwood Project assets, net	678,763	402,242
Fixed assets and other:		
Finance lease assets, net of accumulated DD&A	70,691	—
Leasehold improvements and other assets, net of accumulated DD&A	12,713	10,906
Total fixed assets and other, net	83,404	10,906
Total property, plant and equipment, net	\$ 1,136,299	\$ 789,076

Depreciation, depletion and amortization expenses for the years ended December 31, 2023, 2022 and 2021 were approximately \$98.4 million, \$44.4 million and \$11.5 million, respectively.

Terminal Construction in Progress

During the year ended December 31, 2023, we capitalized approximately \$240.6 million of directly identifiable project costs as construction in progress, inclusive of approximately \$22.4 million in capitalized interest.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Pipeline Construction in Progress

On April 21, 2023, the Company received FERC approval for the construction of the Driftwood pipelines. During the second quarter of 2023, pipeline materials and rights of way of approximately \$14.6 million were transferred to construction in progress. For the year ended December 31, 2023, we also capitalized approximately \$21.4 million of directly identifiable project costs as Pipeline construction in progress, inclusive of approximately \$0.6 million in capitalized interest.

Proved Properties

During the year ended December 31, 2023, we put in production five operated Haynesville wells and participated in nine non-operated Haynesville wells that were put in production.

NOTE 5 — OTHER NON-CURRENT ASSETS

Other non-current assets consist of the following (in thousands):

	December 31,	
	2023	2022
Restricted cash	24,900	24,888
Note receivable	24,189	6,595
Right of use asset — operating leases	12,814	13,303
Investment in unconsolidated entity	6,089	6,089
Pipeline materials and rights of way	—	9,136
Permitting costs	—	916
Land lease and purchase options	\$ —	\$ 300
Other	2,207	2,089
Total other non-current assets	<u>\$ 70,199</u>	<u>\$ 63,316</u>

Restricted Cash

Restricted cash as of December 31, 2023 and December 31, 2022, represents the cash collateralization of letters of credit associated with finance leases.

Note Receivable

In February 2023, the Company issued an amended and restated promissory note due June 14, 2031 (the “Note Receivable”) to an unaffiliated entity engaged in the development of infrastructure projects in the energy industry. The outstanding principal balance of the Note Receivable as of December 31, 2023 was approximately \$24.2 million. The promissory note bears interest at a rate of 6.00%, which is capitalized into the outstanding principal balance annually.

Investment in Unconsolidated Entities

On February 24, 2022, the Company purchased 1.5 million ordinary shares of an unaffiliated entity that provides renewable energy services. The total cost of this investment was approximately \$6.1 million. This investment does not provide the Company with a controlling financial interest in or significant influence over the operating or financial decisions of the unaffiliated entity. The Company’s investment was recorded at cost.

Pipeline materials and rights of way

Pipeline materials and rights of way were transferred to construction in progress in the second quarter of 2023. See Note 4, *Property, Plant and Equipment*.

NOTE 6 — RELATED PARTY TRANSACTIONS

Related Party Contractor Service Fees and Expenses

The Company entered into a one-year independent contractor agreement, effective January 1, 2022, with Mr. Martin Houston, the then-Vice Chairman of the Company’s Board of Directors. Pursuant to the terms and conditions of this agreement, the Company paid Mr. Houston a monthly fee of \$50.0 thousand plus approved expenses. In December 2022, the Company amended the independent contractor agreement to expire on the earlier of (i) termination of Mr. Houston and (ii) December 31, 2023, and to increase the monthly fee to \$55.0 thousand plus approved expenses. For the years ended December 31, 2023 and 2022, the Company paid Mr. Houston \$660.0 thousand and \$625.0 thousand, respectively, for contractor service fees and expenses. As of December 31, 2023 and 2022, there were no balances due to Mr. Houston.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 7 — ACCRUED AND OTHER LIABILITIES

Accrued and other liabilities consist of the following (in thousands):

	December 31,	
	2023	2022
Upstream accrued liabilities	47,652	\$ 71,977
Payroll and compensation	15,423	37,329
Accrued taxes	1,476	730
Driftwood Project development activities	24,455	4,423
Lease liabilities	4,710	2,875
Accrued interest	8,293	5,793
Embedded derivative (Note 9)	13,332	—
Other	8,309	6,053
Total accrued and other liabilities	<u>\$ 123,650</u>	<u>\$ 129,180</u>

NOTE 8 — BORROWINGS

The Company's borrowings consist of the following (in thousands):

	December 31, 2023		
	Principal repayment obligation	Unamortized Discount (DFC)	Carrying value
Senior Secured Convertible Notes due 2025	\$ 83,334	\$ (10,415)	\$ 72,919
Senior Secured Notes due 2025	250,000	(16,954)	233,046
Senior Unsecured Notes due 2028	57,678	(2,241)	55,437
Total borrowings	<u>\$ 391,012</u>	<u>\$ (29,610)</u>	<u>\$ 361,402</u>

	December 31, 2022		
	Principal repayment obligation	Unamortized DFC	Carrying value
Convertible Notes, current	\$ 166,666	\$ (3,110)	\$ 163,556
Convertible Notes, non-current	333,334	(6,219)	327,115
Senior Unsecured Notes due 2028	57,678	(2,585)	55,093
Total borrowings	<u>\$ 557,678</u>	<u>\$ (11,914)</u>	<u>\$ 545,764</u>

Amortization of the borrowings' DFC is a component of Interest expense, net in the Company's Consolidated Statements of Operations. We amortized approximately \$7.1 million, \$2.4 million, and \$3.1 million during the years ended December 31, 2023, 2022, and 2021, respectively.

Senior Secured Convertible Notes due 2025 (Extinguished)

On June 3, 2022, we issued and sold \$500.0 million aggregate principal amount of 6.00% Senior Secured Convertible Notes due May 1, 2025 (the "Extinguished Convertible Notes"). Net proceeds from the Extinguished Convertible Notes were approximately \$488.7 million after deducting fees and expenses. The Extinguished Convertible Notes had quarterly interest payments due on February 1, May 1, August 1, and November 1 of each year and on the maturity date. DFC of approximately \$11.5 million were capitalized.

Partial Redemption

On March 27, 2023, the holder of the Extinguished Convertible Notes delivered to the Company notice to redeem \$166.7 million of the initial principal amount of the Extinguished Convertible Notes at par, plus accrued interest (the "Redemption Amount"). On March 28, 2023, the Company irrevocably deposited the Redemption Amount of approximately \$169.1 million in order to satisfy the redemption and retirement of \$166.7 million principal amount of the Extinguished Convertible Notes, plus accrued interest. As a result of paying the Redemption Amount prior to the Extinguished Convertible Notes' contractual maturity, the Company wrote off approximately \$2.8 million of prorated unamortized DFC, which was recognized within Loss on extinguishment of debt, net, in its Consolidated Statements of Operations.

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Extinguishment

On August 15, 2023, we issued and sold in a private placement \$250.0 million aggregate principal amount of 10% Senior Secured Notes due October 1, 2025 (the “Senior Notes”) and approximately \$83.3 million aggregate principal amount of 6% Secured Convertible Notes (the “Convertible Notes”) due October 1, 2025 (collectively the “Replacement Notes”). The issuance of the Replacement Notes to the holder of the Extinguished Convertible Notes resulted in the satisfaction and discharge of the Company’s outstanding principal repayment obligation under the Extinguished Convertible Notes. As a result, the Company recorded a Loss on extinguishment of debt of approximately \$29.5 million in its Consolidated Statements of Operations.

Amendments to the Replacement Notes Indentures

On January 2, 2024, we amended the indentures governing the Replacement Notes. See Note 19, *Subsequent Events*, for further information.

Senior Secured Notes due 2025

The Senior Notes have quarterly interest payments in cash due on the first day of January, April, July, and October of each year, commencing in October 2023. DFC of approximately \$20.1 million were capitalized and are being amortized over the term of the Senior Notes using the effective interest rate method. Holders of the Senior Notes may force the Company to redeem the applicable Senior Notes for cash upon (i) a fundamental change or (ii) an event of default. On or after October 1, 2024, the holders of the Senior Notes may redeem up to the entire principal amount of the Senior Notes for a cash purchase price equal to the principal amount of the Senior Notes being redeemed, plus accrued and unpaid interest, if the Company’s liquidity falls below (a) \$200.0 million, if the Convertible Notes are not outstanding at such time, or (b) \$250.0 million, if any of the Convertible Notes are outstanding at such time. The Company may provide written notice to each holder of the Senior Notes calling all of such holder’s Senior Notes for redemption for a cash purchase price equal to 100% of the principal amount being redeemed, plus accrued and unpaid interest (the “Optional Redemption”).

Our borrowing obligations under the Senior Notes are collateralized by a first priority lien on the Company’s equity interests in Tellurian Production Holdings LLC (“Tellurian Production Holdings”), a wholly owned subsidiary of Tellurian Inc. Tellurian Production Holdings owns all of the Company’s upstream natural gas assets described in Note 4, *Property, Plant and Equipment*. The Senior Notes contain financial and non-financial covenants, including a minimum cash balance of \$50.0 million. As of December 31, 2023, we remained in compliance with all covenants under the Senior Notes.

As of December 31, 2023, the estimated fair value of the Senior Notes was approximately \$215.3 million. The Level 3 fair value was estimated based on inputs that are observable in the market or that could be derived from, or corroborated with, observable market data, including our stock price and inputs that are not observable in the market.

Senior Secured Convertible Notes due 2025

The Convertible Notes have quarterly interest payments in cash due on the first day of January, April, July, and October of each year, commencing in October 2023. DFC of approximately \$12.3 million were capitalized and are being amortized over the term of the Senior Convertible Notes using the effective interest rate method. The holders of the Convertible Notes have the right to convert the notes into shares of our common stock at an initial conversion rate of 512.8205 shares per \$1,000 principal amount of notes (equivalent to a conversion price of approximately \$1.95 per share of common stock) (the “Conversion Price”), subject to adjustment in certain circumstances, at any time until the second trading day immediately prior to the maturity date (the “Conversion Feature”). The Company will force the holders of the Convertible Notes to convert all of the notes if the trading price of our common stock closes above 300% of the Conversion Price for 20 consecutive trading days and certain other equity conditions are satisfied. Holders of the Convertible Notes may force the Company to redeem the applicable Notes for cash upon (i) a fundamental change or (ii) an event of default. On or after October 1, 2024, the holders of the Convertible Notes may redeem up to the entire principal amount of the notes for a cash purchase price equal to the principal amount of the notes being redeemed, plus accrued and unpaid interest, if the Company’s liquidity falls below (a) \$75.0 million, if the Senior Notes are not outstanding at such time, or (b) \$250.0 million, if any of the Senior Notes are outstanding at such time. The shares subject to conversion are excluded from the computation of diluted loss per share because including it in the computation would have been antidilutive for the periods presented.

Our borrowing obligations under the Convertible Notes are collateralized by a first priority lien on the Company’s equity interests in Tellurian Production Holdings and mortgages of the material real property oil and gas assets of Tellurian Production Holdings LLC and its subsidiaries (together, the “Collateral”). Tellurian Production Holdings owns all of the Company’s upstream natural gas assets described in Note 4, *Property, Plant and Equipment*. The Collateral will be removed as a secured obligation under the Convertible Notes if the Senior Notes are no longer outstanding. The Convertible Notes contain financial and non-financial covenants, including a minimum cash balance of \$50.0 million. As of December 31, 2023, we remained in compliance with all covenants under the Convertible Notes.

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As of December 31, 2023, the estimated fair value of the Convertible Notes was approximately \$70.1 million. The Level 3 fair value was estimated based on inputs that are observable in the market or that could be derived from, or corroborated with, observable market data, including our stock price and inputs that are not observable in the market.

Replacement Notes Embedded Derivatives

As part of the issuance of the Replacement Notes, the Company agreed to issue an aggregate total of 25.7 million shares of its common stock (the “Share Coupon”) to the holders of the Replacement Notes. The Share Coupon is payable quarterly on the first day of January, April, July, and October of each year, commencing on or before October 2023. To the extent that the average daily volume-weighted average price of the common stock of the Company during each quarter is less than \$1.35, the Company will pay a cash amount equal to that difference multiplied by the number of shares issuable for that quarter (the “Cash Shortfall Payments”). Upon any retirement, redemption, or conversion of the Replacement Notes, the Company will issue any and all unpaid Share Coupon plus Cash Shortfall Payments, as applicable (the “Make Whole”).

The Company evaluated the potential embedded features within the Replacement Notes host contracts and determined that the Convertible Feature, Share Coupon, the Cash Shortfall Payments and the Make Whole embedded features required bifurcation as a single unit of account from the Replacement Notes and accounted for them separately at fair value. See Note 9, *Financial Instruments*, for more information on the fair value measurement of the Replacement Notes embedded derivatives.

Senior Unsecured Notes due 2028

On November 10, 2021, we sold in a registered public offering \$50.0 million aggregate principal amount of 8.25% Senior Unsecured Notes due November 30, 2028 (the “Senior Unsecured Notes”). Net proceeds from the Senior Unsecured Notes were approximately \$47.5 million after deducting fees. The underwriter was granted an option to purchase up to an additional \$7.5 million of the Senior Unsecured Notes within 30 days. On December 7, 2021, the underwriter exercised the option and purchased an additional \$6.5 million of the Senior Unsecured Notes resulting in net proceeds of approximately \$6.2 million after deducting fees. The Senior Unsecured Notes have quarterly interest payments due on January 31, April 30, July 31, and October 31 of each year and on the maturity date. As of December 31, 2023, the Company was in compliance with all covenants under the indenture governing the Senior Unsecured Notes. The Senior Unsecured Notes are listed and trade on the NYSE American under the symbol “TELZ,” and are classified as Level 1 within the fair value hierarchy. As of December 31, 2023, the closing market price was \$12.25 per Senior Unsecured Note.

At-the-Market Debt Offering Program

On December 17, 2021, we entered into an at-the-market debt offering program under which the Company may offer and sell, from time to time on the NYSE American, up to an aggregate principal amount of \$200.0 million of additional Senior Unsecured Notes. During the year ended December 31, 2022, we sold approximately \$1.2 million aggregate principal amount of additional Senior Unsecured Notes for total proceeds of approximately \$1.1 million after fees and commissions under our at-the-market debt offering program. On December 30, 2022, the Company terminated the at-the-market debt offering program.

2020 Senior Unsecured Note

On April 29, 2020, we issued a zero coupon \$56.0 million senior unsecured note (the “2020 Unsecured Note”) to an unrelated third party. The 2020 Unsecured Note was repaid in installments with the final contractually required payment made on March 31, 2021.

2019 Term Loan

On May 23, 2019, Driftwood Holdings LP (“Driftwood Holdings”), a wholly owned subsidiary of the Company, entered into a senior secured term loan agreement (the “2019 Term Loan”) to borrow an aggregate principal amount of \$60.0 million. On July 16, 2019, the principal amount was increased by an additional \$15.0 million. Upon maturity or early repayment of the 2019 Term Loan, Driftwood Holdings was obligated to pay to the lender a fee equal to 20% of the principal amount borrowed less financing costs and cash interest paid (the “Final Payment Fee”). We issued to the lender a warrant to purchase approximately 1.5 million shares of our common stock at \$10.00 per share (the “Original Warrant”). On March 3, 2020, the Original Warrant was replaced with a new warrant (the “Replacement Warrant”) which provided the lender with the right to purchase 9.0 million shares of our common stock at \$1.00 per share.

On March 12, 2021 (the “Extinguishment Date”), we finalized a voluntary repayment of the remaining outstanding principal balance of the 2019 Term Loan. The extinguishment of the 2019 Term Loan resulted in an approximately \$2.1 million gain, which was recognized within Gain on extinguishment of debt, net, on our Consolidated Statements of Operations for the year ended December 31, 2021. As a result of repaying the outstanding balance prior to its contractual maturity, an approximately \$4.4 million in unamortized debt issuance costs and discount were written off and included in the computation of the gain from the extinguishment of the 2019 Term Loan for the year ended December 31, 2021.

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The holder of the 2019 Term Loan held approximately 3.5 million unvested warrants that had a fair value of approximately \$6.3 million as of the Extinguishment Date. Due to the extinguishment of the 2019 Term Loan, all the unvested warrants were contractually terminated, and their respective fair value was included in the computation of the gain on extinguishment of the 2019 Term Loan.

2018 Term Loan

On September 28, 2018, Tellurian Production Holdings LLC, a wholly owned subsidiary of Tellurian Inc., entered into a three-year senior secured term loan credit agreement (the “2018 Term Loan”) in an aggregate principal amount of \$60.0 million.

On April 23, 2021, we voluntarily repaid the remaining outstanding principal balance of the 2018 Term Loan. As a result of the voluntary repayment, we recognized an approximately \$0.7 million loss, which was recognized within Gain on extinguishment of debt, net, on our Consolidated Statements of Operations for the year ended December 31, 2021.

NOTE 9 — FINANCIAL INSTRUMENTS

Natural Gas Financial Instruments

The primary purpose of our commodity risk management activities is to hedge our exposure to cash flow variability from commodity price risk due to fluctuations in commodity prices. The Company may use natural gas financial futures and option contracts to economically hedge the commodity price risks associated with a portion of our expected natural gas production. As of December 31, 2023, there were no open natural gas financial instrument positions.

LNG Financial Futures

During the year ended December 31, 2021, we entered into LNG financial futures contracts to reduce our exposure to commodity price fluctuations and to achieve more predictable cash flows relative to two LNG cargos that we were committed to purchase from and sell to unrelated third-party LNG merchants in the normal course of business in January and April 2022. As of December 31, 2023, there were no open LNG financial instrument positions.

Contingent Consideration

On August 18, 2022, the Company completed the acquisition of certain natural gas assets in the Haynesville Shale basin (the “Asset Acquisition”). The Asset Acquisition included cash consideration payable to the sellers of \$7.5 million (the “Contingent Consideration”) if the average NYMEX Henry Hub gas price for the contract delivery months beginning with August 2022 through March 2023 exceeded a specific threshold (the “Threshold”) per MMBtu. The Threshold was not met and, therefore, the Company is not obligated to pay the Contingent Consideration.

Embedded Derivatives

We evaluate embedded features within a host contract to determine whether they are embedded derivatives that should be bifurcated and carried separately at fair value. Embedded derivatives that are not clearly and closely related to the host contract are bifurcated and recorded at fair value with subsequent changes in fair value recorded in Other income (expense), net in the Company’s Consolidated Statement of Operations. As described in Note 8, *Borrowings*, we determined that the Replacement Notes contained embedded features which required bifurcation from the host contracts.

The following table presents the classification of the Company’s financial instruments that are required to be measured at fair value on a recurring basis on the Company’s Consolidated Balance Sheets (in thousands):

	Year ended December 31, 2023	Year ended December 31, 2022
Current Assets:		
Natural Gas Financial Instruments	\$ —	\$ 10,463
LNG Financial Futures	—	—
Current liabilities:		
Contingent Consideration	—	118
Embedded derivatives	13,332	—
Long-term liabilities		
Embedded derivatives	18,892	—

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The following table summarizes the effect of the Company's financial instruments which are included within Other expense, net on the Consolidated Statements of Operations (in thousands):

	<u>Year ended December 31, 2023</u>	<u>Year ended December 31, 2022</u>
Natural gas financial instruments:		
Realized gain (loss)	\$ 23,310	\$ (27,179)
Unrealized (loss) gain	(10,463)	10,463
LNG financial futures contracts:		
Realized gain	—	3,532
Unrealized loss	—	5,161
Contingent Consideration:		
Realized gain	118	—
Unrealized gain	—	3,770
Embedded derivative		
Realized gain	1,554	—
Unrealized gain	17,041	—

The following table summarizes changes in the Company's Embedded Derivatives (in thousands):

	<u>Year ended December 31, 2023</u>
Balance at January 1, 2023	\$ —
Issued	56,005
Settled	(5,186)
Total gains or losses (realized and unrealized) included in earnings	(18,594)
Balance at December 31, 2023	<u>\$ 32,225</u>

The Company's natural gas financial instruments are valued using quoted prices in active exchange markets as of the balance sheet date and are classified as a Level 1 fair value measurement. The fair value of the Company's embedded derivatives as of December 31, 2023 was estimated using a Black-Scholes valuation model which is considered to be a Level 3 fair value measurement.

NOTE 10 — COMMITMENTS AND CONTINGENCIES

Trade Finance Credit Line

On July 19, 2021, we entered into an uncommitted trade finance credit line for up to \$30.0 million that is intended to finance the purchase of LNG cargos for ultimate resale in the normal course of business. On December 7, 2021, the uncommitted trade finance credit line was amended and increased to \$150.0 million. As of December 31, 2023, no amounts were drawn under this credit line.

Minimum Volume Commitments

The Company is subject to gas gathering commitments with unrelated companies which provide dedicated gathering capacity for a portion of the Upstream segment's Haynesville Shale future natural gas production. The gas gathering agreements may require us to make deficiency payments to the extent the Company does not meet the minimum volume commitments per the terms of each contract. The estimated minimum volume deficiency liability as of December 31, 2023 is approximately \$5.0 million.

NOTE 11 — STOCKHOLDERS' EQUITY

At-the-Market Equity Offering Programs

We maintain at-the-market equity offering programs pursuant to which we sell shares of our common stock from time to time on the NYSE American. For the year ended December 31, 2022, we issued 67.7 million shares of our common stock under our at-the-market equity offering programs for net proceeds of approximately \$299.7 million. On December 30, 2022, we terminated the Company's then-existing at-the-market equity offering programs.

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On December 30, 2022, we entered into a new at-the-market equity offering program pursuant to which the Company may sell shares of its common stock from time to time on the NYSE American for aggregate sales proceeds of up to \$500.0 million. For the year ended December 31, 2023, we issued 135.8 million shares of our common stock under our at-the-market equity offering program for net proceeds of approximately \$112.1 million. See Note 19, *Subsequent Events*, for further information.

Common Stock Issuances

On August 6, 2021, we sold 35.0 million shares of our common stock in an underwritten public offering at a price of \$3.00 per share. Net proceeds from this offering, after deducting fees and expenses, were approximately \$100.8 million. The underwriters were granted an option to purchase up to an additional 5.3 million shares of common stock within 30 days. On August 31, 2021, the underwriters exercised this option, which generated net proceeds, after deducting fees, of approximately \$15.1 million.

Common Stock Purchase Warrants

2020 Unsecured Note

In conjunction with the issuance of the 2020 Unsecured Note, we issued a warrant providing the lender with the right to purchase up to 20.0 million shares of our common stock at \$1.542 per share (the “2020 Warrant”). The 2020 Warrant, which vested immediately, will expire in October 2025. The 2020 Warrant was valued using a Black-Scholes option pricing model that resulted in a relative fair value of approximately \$16.1 million on the issuance date and is not subject to subsequent remeasurement. The 2020 Warrant has been classified as equity and is recognized within Additional paid-in capital on our Consolidated Balance Sheets. The 2020 Warrant has been excluded from the computation of diluted loss per share because including it in the computation would have been antidilutive for the periods presented.

2019 Term Loan

During the first quarter of 2021, the lender of the 2019 Term Loan exercised warrants to purchase approximately 6.0 million shares of our common stock for total proceeds of approximately \$8.2 million. As discussed in Note 10, *Borrowings*, the 2019 Term Loan has been repaid in full and the lender no longer holds any warrants.

Preferred Stock

In March 2018, we entered into a preferred stock purchase agreement with BDC Oil and Gas Holdings, LLC (“Bechtel Holdings”), a Delaware limited liability company and an affiliate of Bechtel Energy Inc., pursuant to which we sold to Bechtel Holdings approximately 6.1 million shares of our Series C convertible preferred stock (the “Preferred Stock”).

The holders of the Preferred Stock do not have dividend rights but do have a liquidation preference over holders of our common stock. The holders of the Preferred Stock may convert all or any portion of their shares into shares of our common stock on a one-for-one basis. At any time after “Substantial Completion” of “Project 1,” each as defined in and pursuant to the LSTK EPC Agreement for the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, or at any time after March 21, 2028, we have the right to cause all of the Preferred Stock to be converted into shares of our common stock on a one-for-one basis. The Preferred Stock has been excluded from the computation of diluted loss per share because including it in the computation would have been antidilutive for the periods presented.

NOTE 12 — 2020 SEVERANCE AND REORGANIZATION

Employee Retention Plan

During the first quarter of 2020, we implemented a cost reduction and reorganization plan due to the sharp decline in oil and natural gas prices as well as the negative economic effects of the COVID-19 pandemic. We satisfied all amounts owed to former employees. In July 2020, the Company’s Board of Directors approved an employee retention incentive plan (the “Employee Retention Plan”) aggregating \$12.0 million. The Employee Retention Plan was designed to vest in four equal installments upon the attainment of a ten-day average closing price of the Company’s common stock above \$2.25, \$3.25, \$4.25 and \$5.25 (the “Stock Performance Targets”). During the year ended December 31, 2021, three of the four installments vested and we recognized approximately \$7.9 million in retention charges within General and administrative expenses and Development expenses in our Consolidated Statements of Operations, of which \$3.6 million was paid during 2022. The plan expired on March 31, 2022, and the fourth installment did not vest, as the final Stock Performance Target was not attained.

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NOTE 13 — SHARE-BASED COMPENSATION

We have granted restricted stock and restricted stock units (collectively, “Restricted Stock”), as well as unrestricted stock and stock options, to employees, directors and outside consultants under the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan, as amended (the “2016 Plan”), and the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (the “Legacy Plan”). The maximum number of shares of Tellurian common stock authorized for issuance under the 2016 Plan is 40 million shares of common stock, and no further awards can be made under the Legacy Plan.

For the years ended December 31, 2023, 2022 and 2021, Tellurian recognized approximately \$1.5 million, \$3.6 million and \$6.0 million, respectively, of share-based compensation expense related to all share-based awards. As of December 31, 2023, unrecognized compensation expense, based on the grant date fair value, for all share-based awards totaled approximately \$172.2 million.

Restricted Stock

As of December 31, 2023, we had approximately 26.2 million shares of primarily performance-based Restricted Stock outstanding, of which approximately 14.9 million shares will vest entirely based upon an affirmative FID by the Company’s Board of Directors, as defined in the award agreements, and approximately 10.8 million shares will vest in one-third increments at FID and the first and second anniversaries of FID. The remaining shares of primarily performance-based Restricted Stock, totaling approximately 0.5 million shares, will vest based on other criteria. As of December 31, 2023, no expense had been recognized in connection with performance-based Restricted Stock.

The approximately 26.2 million shares of primarily performance-based and time-based Restricted Stock have been excluded from the computation of diluted loss per share because including them in the computation would have been antidilutive for the periods presented.

Summary of our Restricted Stock transactions for the year ended December 31, 2023 (shares and units in thousands):

	Shares	Weighted-Average Grant Date Fair Value
Unvested at January 1, 2023	27,426	\$ 6.52
Granted ⁽¹⁾	1,993	1.19
Vested	(352)	2.57
Forfeited	(2,868)	2.91
Unvested at December 31, 2023	<u>26,199</u>	<u>6.57</u>

⁽¹⁾ The weighted-average per share grant date fair values of Restricted Stock granted during the years ended December 31, 2022 and 2021 were \$4.46 and \$2.90, respectively.

The total grant date fair value of restricted stock vested during the years ended December 31, 2023, 2022 and 2021 was approximately \$0.9 million, \$1.7 million and \$7.4 million, respectively.

Stock Options

Participants in the 2016 Plan have been granted non-qualified options to purchase shares of common stock. Stock options are granted at a price not less than the market price of the common stock on the date of grant.

Summary of our stock option transactions for the year ended December 31, 2023 (stock options in thousands):

	Stock Options	Weighted Average Exercise Price
Outstanding at January 1, 2023	10,970	\$ 5.01
Granted	—	—
Exercised	—	—
Forfeited or expired	(138)	10.32
Outstanding at December 31, 2023	<u>10,832</u>	<u>4.95</u>
Exercisable at December 31, 2023	<u>10,832</u>	<u>\$ 4.95</u>

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The stock options that were granted to a former member of the Company’s executive management team during the year ended December 31, 2020 vest and become exercisable upon the achievement of both triggers as follows (stock options in thousands):

Service Trigger ⁽¹⁾	Stock Price Trigger ⁽²⁾	Amount
December 15, 2021 ⁽³⁾	\$3.50	3,333
December 15, 2022 ⁽⁴⁾	\$4.50	3,333
December 15, 2023 ⁽⁵⁾	\$5.50	3,334
		10,000

⁽¹⁾ Satisfied through continued employment or other service to the Company through the designated date.

⁽²⁾ Satisfied upon the Company’s common stock price closing at a price per share at or equal to the designated closing price for any ten consecutive trading days.

⁽³⁾ Vested during the year ended December 31, 2021.

⁽⁴⁾ Vested during the year ended December 31, 2022.

⁽⁵⁾ Vested during the year ended December 31, 2023.

The stock options granted during the year ended December 31, 2020, were set to expire on the fifth anniversary of the date of its grant but will now expire in March 2024.

The fair value of each stock option awarded in 2020 was estimated using a Monte Carlo simulation and, due to the service trigger, is being recognized as compensation expense ratably over the vesting term. Valuation assumptions used to value stock options granted during the year ended December 31, 2020 were as follows:

Expected volatility	113.6 %
Expected dividend yields	— %
Risk-free rate	0.4 %

Due to our limited history, the expected volatility is based on a blend of our historical annualized volatility and the implied volatility utilizing options quoted or traded. The expected dividend yield is based on historical yields on the date of grant. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of the grant.

There were no stock options exercised during any of the years ended December 31, 2023, 2022, and 2021. Further, the approximately 10.8 million stock options outstanding have been excluded from the computation of diluted loss per share because including them in the computation would have been antidilutive for the periods presented.

NOTE 14 — INCENTIVE COMPENSATION PROGRAM

On November 18, 2021, the Company’s Board of Directors approved the adoption of the Tellurian Incentive Compensation Program (the “Incentive Compensation Program” or “ICP”). The ICP allows the Company to award short-term and long-term performance and service-based incentive compensation to full-time employees of the Company. ICP awards may be earned with respect to each calendar year and are determined based on guidelines established by the Compensation Committee of the Board of Directors, as administrator of the ICP.

Short-term incentive awards

Short-term incentive (“STI”) awards are payable annually in cash at the discretion of the Company’s Board of Directors. Compensation expense for STI awards is recognized over the performance period when it is probable that the performance condition will be achieved. For the year ended December 31, 2023 we recognized no compensation expense related to STI awards, as compared to approximately \$15.7 million for the year ended December 31, 2022.

Long-term incentive awards

Long-term incentive (“LTI”) awards under the ICP were granted in January 2022 in the form of “tracking units,” at the discretion of the Company’s Board of Directors (the “2021 LTI Award”). Each such tracking unit has a value equal to one share of Tellurian common stock and entitles the grantee to receive, upon vesting, a cash payment equal to the closing price of our common stock on the trading day prior to the vesting date. These tracking units will vest in three equal tranches at grant date, and the first and second anniversaries of the grant date. Non-vested 2021 LTI Awards as of December 31, 2023 during the period were as follows:

TELLURIAN INC. AND SUBSIDIARIES
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	Number of Tracking Units (in thousands)	Price per Tracking Unit
Balance at January 1, 2023	12,719	\$ 1.68
Granted	—	\$ —
Vested	(6,359)	2.13
Forfeited	(368)	1.50
Unvested balance at December 31, 2023	<u>5,992</u>	<u>\$ 0.76</u>

LTI awards under the ICP were granted in February 2023 in the form of “tracking units,” at the discretion of the Compensation Committee of the Company’s Board of Directors (the “2022 LTI Awards”). Each such tracking unit has a value equal to one share of Tellurian common stock and entitles the grantee to receive, upon vesting, a cash payment equal to the closing price of our common stock on the trading day prior to the vesting date. These tracking units will vest in three equal tranches at the grant date and the first and second anniversaries of the grant date. Non-vested 2022 LTI Awards as of December 31, 2023 and awards granted during the period were as follows:

	Number of Tracking Units (in thousands)	Price per Tracking Unit
Balance at January 1, 2023	—	—
Granted	14,802	\$ 2.10
Vested	(4,934)	1.63
Forfeited	(606)	1.46
Unvested balance at December 31, 2023	<u>9,262</u>	<u>\$ 0.76</u>

We recognize compensation expense for awards with graded vesting schedules over the requisite service periods for each separately vesting portion of the award as if each award was in substance multiple awards. Compensation expense for the first tranche of the 2021 LTI Awards and the 2022 LTI Awards that vested at the grant date was primarily recognized over the performance period when it was probable that the performance condition was achieved. Compensation expense for the second and third tranches of the 2021 LTI Awards and the 2022 LTI Awards is recognized on a straight-line basis over the requisite service vesting period. Compensation expense for unvested tracking units is subsequently adjusted each reporting period to reflect the estimated payout levels based on changes in the Company’s stock price and actual forfeitures.

Compensation expense (income) related to the second and third tranches of the 2021 LTI Awards and the 2022 LTI Awards are as follows (in thousands):

	Year Ended December 31,	
	2023	2022
2022 LTI Awards	\$ 5,280	\$ —
2021 LTI Awards	(788)	15,681

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NOTE 15 — INCOME TAXES

Income tax benefit (provision) included in our reported net loss consisted of the following (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Current:			
Federal	\$ —	\$ —	\$ —
State	—	—	—
Foreign	—	—	—
Total Current	—	—	—
Deferred:			
Federal	—	—	—
State	—	—	—
Foreign	—	—	—
Total Deferred	—	—	—
Total income tax benefit (provision)	\$ —	\$ —	\$ —

The sources of loss from operations before income taxes were as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Domestic	\$ (166,694)	\$ (36,591)	\$ (111,114)
Foreign	517	(13,219)	(3,624)
Total loss before income taxes	\$ (166,177)	\$ (49,810)	\$ (114,738)

The reconciliation of the federal statutory income tax rate to our effective income tax rate is as follows:

	Year Ended December 31,		
	2023	2022	2021
Income tax benefit (provision) at U.S. statutory rate	\$ 34,897	\$ 10,460	\$ 24,095
Share-based compensation	(126)	(126)	1,352
Executive compensation	(3,919)	(3,688)	(203)
Change in U.S. state tax rate	—	(1,313)	—
Change in foreign tax rate	—	1,816	—
Disallowed interest	(4,683)	—	—
U.S. state tax	5,494	792	4,333
Change in valuation allowance	(29,877)	(8,871)	(29,648)
R&D Credit	—	748	524
Foreign rate differential	(38)	516	(74)
Other	(1,748)	(334)	(379)
Total income tax benefit (provision)	\$ —	\$ —	\$ —

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Significant components of our deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2023	2022
Deferred tax assets:		
Capitalized costs	\$ 92,758	\$ 85,875
Compensation and benefits	2,299	8,860
Lease liability	34,391	16,086
Disallowed interest expense carryforward	3,974	3,510
Net operating loss carryforwards and credits:		
Federal	124,320	99,922
State	21,036	16,142
Foreign	10,760	11,023
Other, net	14,689	7,080
Deferred tax assets	304,227	248,498
Less valuation allowance	(241,034)	(211,157)
Deferred tax assets, net of valuation allowance	63,193	37,341
Deferred tax liabilities		
Property and equipment	(63,193)	(37,341)
Net deferred tax assets	\$ —	\$ —

As of December 31, 2023, we had federal, state and international net operating loss (“NOL”) carryforwards of approximately \$572.0 million, \$361.1 million and \$44.7 million, respectively. Approximately \$670.6 million of these NOLs have an indefinite carryforward period. All other NOLs will expire between 2036 and 2040.

Due to our historical losses and other available evidence related to our ability to generate taxable income, we have established a valuation allowance to fully offset our federal, state and international deferred tax assets as of December 31, 2023 and 2022. We will continue to evaluate the realizability of our deferred tax assets in the future. The increase in the valuation allowance was approximately \$29.9 million for the year ended December 31, 2023.

In addition, we experienced a Section 382 ownership change in April 2017. An analysis of the annual limitation on the utilization of our NOLs was performed in accordance with IRC Section 382. It was determined that IRC Section 382 will not materially limit the use of our NOLs over the carryover period. We will continue to monitor trading activity in our shares which could cause an additional ownership change. If the Company experiences a Section 382 ownership change, it could further affect our ability to utilize our existing NOL carryforwards.

As of December 31, 2023, the Company determined that it has no uncertain tax positions, interest or penalties as defined within ASC 740-10. The Company does not have unrecognized tax benefits. The Company does not believe that it is reasonably possible that the total unrecognized benefits will significantly increase within the next 12 months.

We are subject to tax in the U.S. and various state and foreign jurisdictions. Federal and state tax returns filed with each jurisdiction remain open to examination under the normal three-year statute of limitations.

Pursuant to ASC 740-30-25-17, the Company recognizes deferred tax liabilities associated with outside basis differences on investments in foreign subsidiaries unless the difference is considered essentially permanent in duration. As of December 31, 2023, the Company has not recorded any deferred taxes on unremitted earnings as the Company has no undistributed earnings and profits. If circumstances change in the foreseeable future and it becomes apparent that some or all of the undistributed earnings and profits will not be reinvested indefinitely, or will be remitted in the foreseeable future, a deferred tax liability will be recorded for some or all of the outside basis difference.

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NOTE 16 — LEASES

Our Driftwood Project land leases are classified as finance leases and include one or more options to extend the lease term for up to 40 years, as well as to terminate the lease within five years, at our sole discretion. We are reasonably certain that those options will be exercised and that our termination rights will not be exercised, and we have, therefore, included those assumptions within our right of use assets and corresponding lease liabilities. Our other land leases are classified as finance leases and include one or more options to extend the lease term for up to 69 years or to terminate the lease within seven years, at our sole discretion. We are reasonably certain that those options and termination rights will not be exercised, and we have, therefore, excluded those assumptions within our right of use assets and corresponding lease liabilities.

Our office space leases are classified as operating leases and include one or more options to extend the lease term up to 10 years, at our sole discretion. As we are not reasonably certain that those options will be exercised, none are recognized as part of our right of use assets and lease liabilities. As none of our leases provide an implicit rate, we have determined our own discount rate.

The following table shows the classification and location of our right-of-use assets and lease liabilities on our Consolidated Balance Sheets (in thousands):

Leases	Consolidated Balance Sheets Classification	December 31,	
		2023	2022
Right of use asset			
Operating	Other Non-Current Assets	\$ 12,814	\$ 13,303
Finance	Property, plant and equipment, net	126,225	56,708
Total Leased Assets		\$ 139,039	\$ 70,011
Liabilities			
Current			
Operating	Accrued and other liabilities	\$ 3,835	\$ 2,734
Finance	Accrued and other liabilities	875	140
Non-Current			
Operating	Other non-current liabilities	10,743	12,148
Finance	Finance lease liabilities	121,450	49,963
Total leased liabilities		\$ 136,903	\$ 64,985

Lease costs recognized in our Consolidated Statements of Operations is summarized as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Lease costs			
Operating lease cost	\$ 3,915	\$ 3,149	\$ 2,519
Finance lease cost			
Amortization of lease assets	3,461	1,174	788
Interest on lease liabilities	9,202	3,978	2,904
Finance lease cost	\$ 12,663	\$ 5,152	\$ 3,692
Total lease cost	\$ 16,578	\$ 8,301	\$ 6,211

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Other information about lease amounts recognized in our Consolidated Financial Statements is as follows:

	December 31,	
	2023	2022
Lease term and discount rate		
Weighted average remaining lease term (years)		
Operating lease	3.5	4.5
Finance lease	36.1	48.4
Weighted average discount rate		
Operating lease	6.4 %	6.2 %
Finance lease	8.7 %	9.4 %

The following shows other quantitative information for our operating and finance leases (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	\$ 4,333	\$ 3,423	\$ 2,953
Operating cash flows from finance leases	\$ 7,950	\$ 3,674	\$ 1,813
Financing cash flows from finance leases	\$ 512	\$ 132	\$ 1,926

The table below presents an analysis of the maturity of our lease liability on an undiscounted basis and reconciles those amounts to the present value of the lease liability as of December 31, 2022 (in thousands):

	Operating	Finance
2024	\$ 4,666	\$ 10,491
2025	4,721	10,491
2026	4,756	10,491
2027	1,954	10,491
2028	275	10,491
After 2028	—	322,334
Total lease payments	\$ 16,372	\$ 374,789
Less: discount	1,794	252,465
Present value of lease liability	\$ 14,578	\$ 122,324

NOTE 17 — SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides information regarding the net changes in working capital (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Accounts receivable	\$ 50,941	\$ (67,462)	\$ (4,770)
Prepaid expenses and other current assets	(9,250)	5,801	(2,536)
Accounts payable	(17,950)	1,953	(5,514)
Accounts payable due to related parties	—	—	(910)
Accrued liabilities ¹	(2,851)	44,548	55,884
Other, net	—	(793)	(1,137)
Net changes in working capital	\$ 20,890	\$ (15,953)	\$ 41,017

¹ Excludes changes in the Company's derivative assets and liabilities.

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The following table provides supplemental disclosure of cash flow information (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Non-cash accruals of property, plant and equipment and other non-current assets	\$ 48,096	\$ 13,323	\$ 56,305
Non-cash settlement of Embedded derivative	\$ 4,899	—	—
Non-cash settlement of withholding taxes associated with the 2019 bonus paid and vesting of certain awards	—	—	3,064
Non-cash settlement of the 2019 bonus paid	—	—	5,430
Asset retirement obligation additions and revisions	—	1,533	76

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of such amounts shown in the Consolidated Statements of Cash Flows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Cash and cash equivalents	\$ 75,789	\$ 474,205	\$ 305,496
Current restricted cash	4,688	9,375	—
Non-current restricted cash	24,900	24,888	1,778
Total cash, cash equivalents and restricted cash in the statement of cash flows	<u>\$ 105,377</u>	<u>\$ 508,468</u>	<u>\$ 307,274</u>

NOTE 18 — DISCLOSURE ABOUT SEGMENTS AND RELATED INFORMATION

The Upstream segment is organized and operates to produce, gather and deliver natural gas and to acquire and develop natural gas assets. The Midstream segment is organized to develop, construct and operate LNG terminals and pipelines. The Marketing & Trading segment is organized and operates to purchase and sell natural gas produced primarily by the Upstream segment, market the Driftwood terminal's LNG production capacity and trade LNG. These operating segments represent the Company's reportable segments. The remainder of our business is presented as "Corporate," and consists of corporate costs and intersegment eliminations. The Company's Chief Operating Decision Maker does not currently assess segment performance or allocate resources based on a measure of total assets. Accordingly, a total asset measure has not been provided for segment disclosure.

Year ended December 31, 2023	Upstream	Midstream	Marketing & Trading	Corporate	Consolidated
Revenues from external customers ⁽¹⁾	\$ 18,047	\$ —	\$ 148,081	\$ —	\$ 166,128
Intersegment revenues (purchases) ⁽²⁾⁽³⁾	148,081	(7,969)	(135,781)	(4,331)	—
Segment operating income (loss) ⁽⁴⁾	(55,501)	(55,289)	(7,306)	(30,566)	(148,662)
Interest expense, net	1,506	(1,007)	6	(18,552)	(18,047)
Loss on extinguishment of debt, net	—	—	—	(32,295)	(32,295)
Other income (loss), net	1,193	—	12,783	18,850	32,827
Consolidated loss before tax					<u>\$ (166,177)</u>

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Year ended December 31, 2022	Upstream	Midstream	Marketing & Trading	Corporate	Consolidated
Revenues from external customers ⁽¹⁾	\$ 15,993	\$ —	\$ 375,933	\$ —	\$ 391,926
Intersegment revenues (purchases) ⁽²⁾⁽³⁾	254,984	(1,760)	(241,229)	(11,995)	—
Segment operating income (loss) ⁽⁴⁾	130,663	(80,626)	(31,192)	(36,618)	(17,773)
Interest expense, net	—	(1,751)	(454)	(11,655)	(13,860)
Gain on extinguishment of debt, net	—	—	—	—	—
Other income (loss), net	3,770	—	(22,912)	964	(18,177)
Consolidated loss before tax					<u>\$ (49,810)</u>

Year ended December 31, 2021	Upstream	Midstream	Marketing & Trading	Corporate	Consolidated
Revenues from external customers ⁽¹⁾	\$ 2,317	\$ —	\$ 68,958	\$ —	\$ 71,275
Intersegment revenues (purchases) ⁽²⁾⁽³⁾	49,182	—	(44,755)	(4,427)	—
Segment operating loss ⁽⁴⁾	(5,651)	(42,040)	(22,889)	(42,153)	(112,733)
Interest expense, net	(1,642)	(4,722)	—	(3,014)	(9,378)
Gain on extinguishment of debt, net	(665)	2,087	—	—	1,422
Other (loss) income , net	(1,284)	(2,494)	9,460	269	5,951
Consolidated loss before tax					<u>\$ (114,738)</u>

(1) The Marketing & Trading segment markets to third party-purchasers most of the Company's natural gas production from the Upstream segment.

(2) The Marketing & Trading segment purchases most of the Company's natural gas production from the Upstream segment. Intersegment revenues are eliminated at consolidation.

(3) Intersegment revenues related to the Marketing & Trading segment are a result of cost allocations to the Corporate component using a cost plus transfer pricing methodology. Intersegment revenues related to the Corporate component are associated with intercompany interest charged to the Midstream segment. Intersegment revenues are eliminated at consolidation.

(4) Operating profit (loss) is defined as operating revenues less operating costs and allocated corporate costs.

	Year Ended December 31,		
	2023	2022	2021
Capital expenditures			
Upstream	\$ 112,992	\$ 347,240	\$ 32,364
Midstream	200,127	199,283	25,501
Marketing & Trading	490	675	—
Total capital expenditures for reportable segments	313,609	547,198	57,865
Corporate capital expenditures	3,896	5,690	—
Consolidated capital expenditures	<u>\$ 317,505</u>	<u>\$ 552,888</u>	<u>\$ 57,865</u>

NOTE 19 — SUBSEQUENT EVENTS

Amendments to Replacement Notes Indentures

January Amendments

On January 2, 2024, we amended the supplemental indentures governing the Replacement Notes and issued approximately 47.8 million shares of common stock to the holder of the Replacement Notes to repay approximately \$37.9 million of the outstanding principal amount of the notes plus accrued interest of approximately \$7.5 million (the “January Transaction”). As part of the January Transaction, the minimum cash balance of \$50.0 million was reduced to \$40.0 million for the limited period set forth in such indentures and the Company's liquidity threshold of \$250.0 million was reduced to \$212.1 million.

February Amendments

On February 22, 2024, we closed an additional transaction (the “February Transaction”) with the holder of the Replacement Notes. The quarterly cash interest payment due, and any stock shortfall payment owed, on April 1, 2024 in respect of the Replacement Notes will be added to the aggregate principal amounts of the applicable notes and we issued all shares due to the holder with respect to the Share Coupon, subject to certain lockup provisions and anti-shortening restrictions. The Company is required to use its reasonable best efforts to sell its upstream natural gas exploration and production assets and to use the

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

proceeds from such sale to repay amounts due under the Senior Notes. The Company's minimum cash balance was reduced as set forth in the supplemental indentures.

The Convertible Notes conversion price is now approximately \$1.05 per share, with the number of shares of common stock of the Company issuable upon conversion limited to approximately 42.7 million. The remaining principal amount of the Convertible Notes will remain outstanding as a non-convertible instrument. The Convertible Notes, including the non-convertible component of those notes are required to be paid monthly over a period of 10 months beginning on January 1, 2025. The right of the holder of the Convertible Notes to cause the Company to redeem those notes on or after October 1, 2024 as a result of a failure to satisfy a liquidity threshold has been eliminated.

Tellurian Investments LLC, a wholly owned subsidiary of the Company, provided a non-recourse pledge of all of its equity interests in the principal properties of the Company comprising the Driftwood Project and a certain intercompany note to secure the obligations under the indentures governing the Replacement Notes. Upon repayment in full of the Senior Notes, substantially all collateral securing the Convertible Notes will be released.

At-the-Market Equity Offering Program

Subsequent to December 31, 2023, and through the date of this filing, we issued approximately 29.6 million shares of our common stock under our at-the-market equity offering program for net proceeds of approximately \$17.8 million. As of the date of this filing, we have availability to raise aggregate gross sales proceeds of approximately \$366.1 million under this at-the-market equity offering program.

Announcement to explore the sale of upstream natural gas assets

As part of Management's Plans to alleviate substantial doubt, on February 6, 2024, we announced our intention to explore the sale of the Company's upstream natural gas assets. The carrying value of our upstream natural gas assets are disclosed in Note 4, *Property, Plant and Equipment*.

TELLURIAN INC.
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

SUPPLEMENTAL DISCLOSURES ABOUT NATURAL GAS PRODUCING ACTIVITIES

In accordance with FASB and SEC disclosure requirements for natural gas producing activities, this section provides supplemental information on Tellurian's natural gas producing activities in six separate tables. Tables I through III provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables IV through VI present information on the Company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves and changes in estimated discounted future net cash flows.

Table I — Capitalized Costs Related to Natural Gas Producing Activities

Capitalized costs related to Tellurian's natural gas producing activities are summarized as follows (in thousands):

	December 31,		
	2023	2022	2021
Proved properties	\$ 561,303	\$ 468,351	\$ 113,950
Unproved properties	—	—	—
Gross capitalized costs	561,303	468,351	113,950
Accumulated DD&A	(187,171)	(92,423)	(48,637)
Net capitalized costs	<u>\$ 374,132</u>	<u>\$ 375,928</u>	<u>\$ 65,313</u>

Table II — Costs Incurred in Property Acquisitions, Exploration and Development

Costs incurred in natural gas property acquisition (inclusive of producing well costs), exploration and development activities are summarized as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Property acquisitions:			
Proved	\$ —	\$ 135,974	\$ 3,409
Unproved	—	—	—
Exploration costs	—	—	—
Development costs	116,045	210,546	28,955
Costs incurred	<u>\$ 116,045</u>	<u>\$ 346,520</u>	<u>\$ 32,364</u>

Table III — Results of Operations for Natural Gas Producing Activities

The following table includes revenues and expenses directly associated with our natural gas and condensate producing activities. It does not include any interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas operations. Tellurian's results of operations from natural gas and condensate producing activities for the periods presented are as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Natural gas sales	\$ 166,128	\$ 270,977	\$ 51,499
Operating costs	88,276	53,963	20,576
Depreciation, depletion and amortization	95,202	43,966	10,998
Total operating costs and expenses	183,478	97,929	31,574
Results of operations	<u>\$ (17,350)</u>	<u>\$ 173,048</u>	<u>\$ 19,925</u>

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Table IV — Natural Gas Reserve Quantity Information

Our estimated proved reserves are located in Louisiana. We caution that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are expected to change as further information becomes available. Material revisions of reserve estimates may occur in the future, development and production of the natural gas and condensate reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in these estimates.

The estimates of our proved reserves as of December 31, 2023, 2022 and 2021 have been prepared by Netherland, Sewell & Associates, Inc., independent petroleum consultants.

	Gas (MMcf)	Gas Equivalent (MMcfe)
Proved reserves:		
December 31, 2020	99,508	99,508
Extensions, discoveries and other additions	202,897	202,897
Revisions of previous estimates	35,237	35,237
Production	(14,306)	(14,306)
Sale of reserves-in-place	—	—
Purchases of reserves-in-place	—	—
December 31, 2021	323,336	323,336
Extensions, discoveries and other additions	113,047	113,047
Revisions of previous estimates	(52,185)	(52,185)
Production	(47,322)	(47,322)
Sale of reserves-in-place	—	—
Purchases of reserves-in-place	108,017	108,017
December 31, 2022	444,893	444,893
Extensions, discoveries and other additions	983	983
Revisions of previous estimates	(179,737)	(179,737)
Production	(72,476)	(72,476)
Sale of reserves-in-place	(15,627)	(15,627)
Purchases of reserves-in-place	—	—
December 31, 2023	178,036	178,036
Proved developed reserves:		
December 31, 2021	73,927	73,927
December 31, 2022	218,382	218,382
December 31, 2023	178,036	178,036
Proved undeveloped reserves:		
December 31, 2021	249,409	249,409
December 31, 2022	226,511	226,511
December 31, 2023	—	—

2022 to 2023 Overall Reserve Changes

- The Company added 1 Bcfe of proved developed reserves from drilling activities.
- The Company had total negative revisions of approximately 180 Bcfe, comprised primarily of a 170 Bcfe negative revision from removing proved undeveloped locations due to uncertainty regarding the Company's future commitment to capital, a 12 Bcfe negative revision from decreases in commodity prices, a 26 Bcfe negative revision from well performance and a 27 Bcfe positive revision from changes in ownership.
- The Company divested 16 Bcfe of proved undeveloped reserves.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2022 to 2023 PUD Changes

- The Company had total negative revisions of approximately 170 Bcfe from removing proved undeveloped locations due to uncertainty regarding the Company's future commitment to capital
- The Company divested 16 Bcfe of proved undeveloped reserves.
- The Company converted approximately 41 Bcfe from proved undeveloped to proved developed reserves.

2021 to 2022 Overall Reserve Changes

- The Company added 113 Bcfe of proved reserves comprised of 89 Bcfe from additional proved undeveloped locations and 24 Bcfe of proved developed reserves from drilling activities.
- The Company had total negative revisions of approximately 52 Bcfe, comprised primarily of a 38 Bcfe negative revision from removing proved undeveloped locations that now fall outside of the SEC mandated five-year development window, a 25 Bcfe negative revision from changes in lateral lengths and ownership, a 3 Bcfe negative revision from increased operational costs, partially offset by an 8 Bcfe positive revision from improved well performance, and a 6 Bcfe positive revision due to an increase in commodity prices. The removal of the proved undeveloped locations that fell outside of the five-year development window resulted from a re-prioritization of activity due to (i) our asset acquisition and (ii) unanticipated third party development activity that caused an existing well to be shut in and unable to return to production and thereby required us to alter our drilling schedule to preserve the affected leases.
- During the year ending December 31, 2022, we acquired approximately 108 Bcfe primarily related to the acquisition of natural gas assets.

2021 to 2022 PUD Changes

- The Company added approximately 89 Bcfe from additional proved undeveloped locations.
- The Company had total negative revisions of approximately 44 Bcfe, comprised of a 38 Bcfe negative revision from removing proved undeveloped locations that now fall outside of the SEC mandated five-year development window, a 13 Bcfe negative revision from changes in lateral lengths and ownership, partially offset by a 5 Bcfe positive revision from improved well performance, and a 2 Bcfe positive revision due to an increase in commodity prices.
- During the year ending December 31, 2022, we acquired approximately 71 Bcfe of proved undeveloped reserves primarily related to the acquisition of natural gas assets.
- The Company converted approximately 138 Bcfe from proved undeveloped reserves to proved developed reserves.

2020 to 2021 Overall Reserve Changes

- Added 203 Bcfe of proved reserves comprised of 152 Bcfe from additional proved undeveloped locations and 51 Bcfe of proved developed reserves from drilling activities.
- Had total positive revisions of approximately 35 Bcfe, comprised primarily of a 9 Bcfe positive revision due to an increase in commodity prices, a 15 Bcfe positive revision from changes in ownership and an 11 Bcfe positive revision from improved well performance.

2020 to 2021 PUD Changes

- Added approximately 152 Bcfe from additional proved undeveloped locations.
- Had total positive revisions of approximately 25 Bcfe, comprised of a 3 Bcfe positive revision due to an increase in commodity prices, a 16 Bcfe positive revision from changes in ownership and a 6 Bcfe positive revision from improved well performance.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Table V — Standardized Measure of Discounted Future Net Cash Flows Related to Proved Natural Gas Reserves

ASC 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Tellurian has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2023, 2022 and 2021 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of natural gas and condensate to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on the continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates, including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the FASB and do not necessarily reflect our expectations of actual revenue to be derived from those reserves or their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved natural gas and condensate reserves based on the standardized measure (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Future cash inflows	\$ 326,246	\$ 2,441,930	\$ 945,651
Future production costs	(102,356)	(341,925)	(133,909)
Future development costs	(56,207)	(360,107)	(211,836)
Future income tax provisions	—	(257,908)	(54,401)
Future net cash flows	167,683	1,481,990	545,505
Less effect of a 10% discount factor	(42,254)	(445,686)	(181,302)
Standardized measure of discounted future net cash flows	<u>\$ 125,429</u>	<u>\$ 1,036,304</u>	<u>\$ 364,203</u>

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Table VI — Changes in Standardized Measure of Discounted Future Net Cash Flows Related to Proved Natural Gas Reserves

The following sets forth the changes in the standardized measure of discounted future net cash flows (in thousands):

December 31, 2020	\$	6,885
Sales and transfers of gas and condensate produced, net of production costs		(39,806)
Net changes in prices and production costs		110,850
Extensions, discoveries, additions and improved recovery, net of related costs		255,246
Development costs incurred		—
Revisions of estimated development costs		10,643
Revisions of previous quantity estimates		35,012
Accretion of discount		688
Net change in income taxes		(27,455)
Purchases of reserves in place		—
Sales of reserves in place		—
Changes in timing and other		12,140
December 31, 2021	\$	364,203
Sales and transfers of gas and condensate produced, net of production costs		(236,374)
Net changes in prices and production costs		503,099
Extensions, discoveries, additions and improved recovery, net of related costs		255,970
Development costs incurred		154,931
Revisions of estimated development costs		(105,352)
Revisions of previous quantity estimates		(143,398)
Accretion of discount		36,420
Net change in income taxes		(127,154)
Purchases of reserves in place		262,050
Sales of reserves in place		—
Changes in timing and other		71,909
December 31, 2022	\$	1,036,304
Sales and transfers of gas and condensate produced, net of production costs		(101,438)
Net changes in prices and production costs		(660,129)
Extensions, discoveries, additions and improved recovery, net of related costs		1,227
Development costs incurred		75,788
Revisions of estimated development costs		(88,121)
Revisions of previous quantity estimates		(331,376)
Accretion of discount		63,350
Net change in income taxes		154,609
Purchases of reserves in place		—
Sales of reserves in place		(30,124)
Changes in timing and other		5,339
December 31, 2023	\$	125,429

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Octávio Simões, the Company's Chief Executive Officer, in his capacity as co-principal executive officer, Daniel Belhumeur, the Company's President, in his capacity as co-principal executive officer, and Simon Oxley, the Company's Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2023, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company's disclosure controls and procedures were effective, providing effective means to ensure that the information we are required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and accumulated and communicated to our management, including our co-principal executive officers and principal financial officer, to allow timely decisions regarding required disclosure. We periodically review the design and effectiveness of our disclosure controls, including compliance with various laws and regulations that apply to our operations both inside and outside the U.S. We make modifications to improve the design and effectiveness of our disclosure controls and may take other corrective action if our reviews identify deficiencies or weaknesses in our controls.

Management's Annual Report on Internal Control Over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is set forth in Item 8 of Part II of this Annual Report on Form 10-K.

The independent auditors report called for by Item 308(b) of Regulation S-K is set forth in Item 8 of Part II of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended December 31, 2023, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Insider Trading Arrangements and Policies

During the quarter ended December 31, 2023, none of our directors or executive officers adopted or terminated a "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement" (as those terms are defined in Item 408 of Regulation S-K). In addition, we did not adopt or terminate a Rule 10b5-1 trading arrangement during the quarter ended December 31, 2023.

Construction Incentive Award

On February 16, 2024, the Compensation Committee of the Company's Board of Directors approved the issuance of a cash incentive award to Simon Oxley, the Company's Chief Financial Officer, in the amount set forth below (the "Award") in connection with the development of Phases 1 through 4 (each, a "Phase") of the Company's Driftwood LNG facility pursuant to the four LSTK EPC agreements for the Driftwood terminal, dated November 10, 2017, between Driftwood LNG and Bechtel (each as amended, restated, modified, extended or supplemented, or any successor contracts or arrangements with respect to the engineering, procurement and construction of the Driftwood facility, an "EPC Contract"):

Name and principal position	Award			
	Phase 1	Phase 2	Phase 3	Phase 4
Simon G. Oxley Chief Financial Officer	\$4,800,000.00	\$2,400,000.00	\$2,400,000.00	\$2,400,000.00

The general terms of the Award are as follows:

- Vesting.** Twenty-five percent (25%) of the Award allocated to any Phase of the Driftwood facility will vest and become payable on each of the first, second, third and fourth anniversaries of the date on which a notice to proceed or similar action or authorization is issued and delivered by Driftwood LNG under an EPC Contract to commence the performance of work on the applicable Phase of the Driftwood facility (the "NTP Date"). Vesting may be accelerated in certain circumstances.

- Expiration. The Award will expire on April 17, 2028 (the “Expiration Date”). If the NTP Date for any Phase does not occur by the Expiration Date, entitlement to the Award allocated to such Phase will lapse and be forfeited without any right to compensation.

A form of the construction incentive award agreement is filed or incorporated by reference as Exhibit 10.24 to this Annual Report on Form 10-K and is incorporated herein by reference. The foregoing summary is qualified in its entirety by the terms of the form of agreement.

Amendments to Replacement Notes Indentures

We amended the indentures governing the Replacement Notes on February 22, 2024, as described in Note 19, *Subsequent Events*, to the Consolidated Financial Statements.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2023 Annual Meeting of Stockholders to be filed not later than April 29, 2024.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2023 Annual Meeting of Stockholders to be filed not later than April 29, 2024.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTER

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2023 Annual Meeting of Stockholders to be filed not later than April 29, 2024.

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

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2023 Annual Meeting of Stockholders to be filed not later than April 29, 2024.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2023 Annual Meeting of Stockholders to be filed not later than April 29, 2024.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements.* Tellurian’s consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules.* Our financial statement schedules filed herewith are set forth in Item 8 of Part II of this report as follows: All valuation and qualifying accounts schedules were omitted since the subject matter thereof is either not present or is not present in amounts sufficient to require submission of the schedule.
3. *Exhibits.* The exhibits listed below are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

Exhibit No.	Description
1.1‡	Distribution Agency Agreement, dated as of December 30, 2022, by and between Tellurian Inc. and T.R. Winston & Company, LLC (incorporated by reference to Exhibit 1.1 to the Company’s Current Report on Form 8-K filed December 30, 2022)
3.1	Amended and Restated Certificate of Incorporation of Tellurian Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on June 7, 2023)
3.1.1	Certificate of Designations of Series C Convertible Preferred Stock of Tellurian Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on March 21, 2018)
3.2	Second Amended and Restated By-Laws of Tellurian Inc., effective as of December 8, 2023 (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on December 11, 2023)
4.1*	Description of Capital Stock and Debt Securities
4.2	Form of Warrant to Purchase Common Stock (incorporated by reference to Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2023)
4.3	Indenture, dated as of November 10, 2021, by and between Tellurian Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K filed on November 10, 2021)
4.3.1	First Supplemental Indenture, dated as of November 10, 2021, by and between Tellurian Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.2 to the Company’s Current Report on Form 8-K filed on November 10, 2021))
4.3.2	Second Supplemental Indenture, dated as of November 10, 2021, by and between Tellurian Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.5 to the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2021)
4.3.3	Form of 8.25% Senior Note due 2028 (included as Exhibit A to Exhibit 4.5)
4.4	Indenture, dated as of June 3, 2022, by and between Tellurian Inc., as issuer, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K filed on June 3, 2022)
4.4.1	Eighth Supplemental Indenture, dated as of August 15, 2023, by and among Tellurian Inc., as issuer, and Wilmington Trust, National Association, as trustee, and the collateral agent named therein, relating to the 10.00% Senior Secured Notes due 2025 (incorporated by reference to Exhibit 4.2 to the Company’s Current Report on Form 8-K filed on August 16, 2023)
4.4.2	First Amendment to Eighth Supplemental Indenture, dated as of January 2, 2024, by and among Tellurian Inc., as issuer, and Wilmington Trust, National Association, as trustee, and the collateral agent named therein, relating to the 10.00% Senior Secured Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K filed on January 2, 2024)
4.4.3†‡*	Second Amendment to Eighth Supplemental Indenture, dated as of February 22, 2024, by and among Tellurian Inc., as issuer, Wilmington Trust, National Association, as trustee, and the collateral agent named therein, relating to the 10.00% Senior Secured Notes due 2025
4.4.4*	Form of 10.00% Senior Secured Note due 2025
4.4.5	Ninth Supplemental Indenture, dated as of August 15, 2023, by and among Tellurian Inc., as issuer, and Wilmington Trust, National Association, as trustee, and the collateral agent named therein, relating to the 6.00% Senior Secured Convertible Notes due 2025 (incorporated by reference to Exhibit 4.3 to the Company’s Current Report on Form 8-K filed on August 16, 2023)

Exhibit No.	Description
4.4.6	First Amendment to Ninth Supplemental Indenture, dated as of January 2, 2024, by and among Tellurian Inc., as issuer, and Wilmington Trust, National Association, as trustee, and the collateral agent named therein, relating to the 6.00% Senior Secured Convertible Notes due 2025 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on January 2, 2024)
4.4.7‡*	Second Amendment to Ninth Supplemental Indenture, dated as of February 22, 2024, by and among Tellurian Inc., as issuer, Wilmington Trust, National Association, as trustee, and the collateral agent named therein, relating to the 6.00% Senior Secured Convertible Notes due 2025
4.4.8*	Form of 6.00% Senior Secured Convertible Note due 2025 (included as Exhibit B to Exhibit 4.4.7)
10.1††	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 13, 2017)
10.1.1	Change Order CO-001, dated as of May 18, 2018, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018)
10.1.2††	Change Order CO-002, dated as of July 24, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.1.3††	Change Order CO-003, executed on July 24, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.1.4††	Change Order CO-004, executed on October 21, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.5.4 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019)
10.1.5††	Change Order CO-005, executed on December 17, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.5.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019)
10.1.6††	Change Order CO-006, executed on October 20, 2020, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.3.6 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020)
10.1.7††	Change Order CO-007, dated as of March 24, 2022, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022)
10.1.8††	Change Order CO-008, dated as of March 30, 2022, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022)
10.1.9‡	Change Order CO-009, dated as of July 15, 2022, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Energy Inc. (formerly known as Bechtel Oil, Gas and Chemicals, Inc.) (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022)

Exhibit No.	Description
10.1.10‡	Change Order CO-010, dated as of October 10, 2022, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Energy Inc. (formerly known as Bechtel Oil, Gas and Chemicals, Inc.) (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2022)
10.1.11‡	Change Order CO-011, dated as of February 27, 2023, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Energy Inc. (formerly known as Bechtel Oil, Gas and Chemicals, Inc.) (incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2023)
10.2††	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 2 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K filed on November 13, 2017)
10.2.1	Change Order CO-001, dated as of May 18, 2018, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 2 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2018)
10.2.2††	Change Order CO-002, executed on July 24, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 2 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.2.3††	Change Order CO-003, executed on October 21, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 2 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.6.3 to the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2019)
10.2.4††	Change Order CO-004, dated as of January 21, 2020, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 2 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2020)
10.3††	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 3 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.3 to the Company’s Current Report on Form 8-K filed on November 13, 2017)
10.3.1	Change Order CO-001, dated as of May 18, 2018, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 3 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2018)
10.3.2	Change Order CO-002, executed on July 24, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 3 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.6 to the Company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.3.3††	Change Order CO-003, executed on October 21, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 3 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.7.3 to the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2019)
10.3.4††	Change Order CO-004, dated as of January 21, 2020, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 3 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2020)

Exhibit No.	Description
10.4††	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 4 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on November 13, 2017)
10.4.1	Change Order CO-001, dated as of May 18, 2018, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 4 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018)
10.4.2	Change Order CO-002, executed on July 24, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 4 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.4.3††	Change Order CO-003, executed on October 21, 2019, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 4 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.8.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019)
10.4.4††	Change Order CO-004, dated as of January 21, 2020, to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 4 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2020)
10.5‡	Securities Purchase Agreement, dated as of August 8, 2023, by and between Tellurian Inc. and the investor named therein (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022)
10.6	Redemption Letter Agreement, dated as of August 8, 2023, by and among Tellurian Inc. and the other parties named therein (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022)
10.7‡	Letter Agreement, dated as of December 28, 2023, by and between Tellurian Inc. and the investor named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 28, 2023)
10.8‡*	Letter Agreement, dated as of February 22, 2024, by and between Tellurian Inc. and the investor named therein
10.9†	Independent Contractor Agreement, dated as of March 30, 2022, by and between Tellurian Inc. and Martin Houston (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022)
10.9.1†	Amendment to Independent Contractor Agreement, dated as of December 14, 2022, by and between Tellurian Inc. and Martin Houston (incorporated by reference to Exhibit 10.13.1 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2022)
10.9.2†*	Second Amendment to Independent Contractor Agreement, dated as of February 16, 2024, by and between Tellurian Inc. and Martin Houston
10.10†‡*	Amended and Restated Chief Executive Officer Employment Agreement, effective as of February 19, 2024, by and between Tellurian Inc. and Octávio Simões
10.11†	Employment Letter Agreement by and between Tellurian Services LLC and Daniel A. Belhumeur, dated as of September 23, 2016 (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-4/A filed on November 8, 2016)
10.12†	Employment Letter Agreement, by and between Tellurian Services LLC and Khaled Sharafeldin, dated as of January 9, 2017 (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.13†‡	Executive Chairman Employment Agreement, effective as of October 1, 2021, by and between Tellurian Inc. and Charif Souki (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 4, 2021)
10.14†*	Separation Agreement and General Release, dated as of December 19, 2023, by and between Tellurian Inc. and Charif Souki

Exhibit No.	Description
10.15†‡	Separation Agreement and General Release, dated as of March 5, 2023, by and between Tellurian Inc. and L. Kian Granmayeh (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2023)
10.16†‡	Tellurian Inc. Executive Severance Plan, effective as of January 6, 2022 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on January 6, 2022)
10.17†‡	Tellurian Inc. Employee Severance Plan, effective as of January 1, 2022 (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2021)
10.18†	Form of Indemnification Agreement (Officers) (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.19†	Form of Indemnification Agreement (Directors) (incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019)
10.20† ¹	Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 22, 2017)
10.20.1†	Form of Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 31, 2018)
10.20.2†	Form of Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (incorporated by reference to Exhibit 10.23.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020)
10.20.3†	Form of Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (Directors) (incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)
10.20.4†	Form of Restricted Stock Unit Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Employees) (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020)
10.20.5†	Form of Restricted Stock Unit Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021)
10.20.6†	Form of Restricted Stock Unit Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.18.7 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2021)
10.20.7†	Form of Stock Option Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.20.8†	Stock Option Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan, dated as of December 15, 2020, by and between Tellurian Inc. and Charif Souki (incorporated by reference to Exhibit 10.23.8 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020)
10.20.9†	Form of Omnibus Amendment to Outstanding Restricted Stock Agreement under Tellurian Inc. Amended and Restated 2016 Omnibus Incentive Compensation Plan, effective as of January 6, 2022 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 6, 2022)
10.21†	Tellurian Inc. Incentive Compensation Program, effective as of November 18, 2021 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 6, 2022)
10.21.1†	Form Long Term Incentive Award Agreement under the Tellurian Inc. Incentive Compensation Program (U.S. Selected Senior Management) (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on January 6, 2022)
10.21.2†	Long Term Incentive Award Agreement under the Tellurian Inc. Incentive Compensation Program, effective as of January 13, 2022, by and between Tellurian Inc. and Khaled Sharafeldin (incorporated by reference to Exhibit 10.19.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2021)
10.22†	Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on February 13, 2017)
10.22.1†	Form of Restricted Stock Amendment Letter regarding the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on February 13, 2017)

Exhibit No.	Description
10.22.2†	Form of Notice of Grant and Restricted Stock Award Agreement pursuant to the 2016 Tellurian Investments Omnibus Incentive Plan (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on February 13, 2017)
10.22.3†	Form of Amendment to Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (Employees) (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.22.4†	Form of Omnibus Amendment to Outstanding Restricted Stock Agreement under Tellurian Investments Inc. 2016 Omnibus Incentive Plan, effective as of January 6, 2022 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on January 6, 2022)
10.23†	Form of Construction Incentive Award Agreement (U.S. Selected Senior Management) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 23, 2018)
10.24†	Form of Construction Incentive Award Agreement (U.S. Employees) (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018)
10.25†	2020 Cash Incentive Award Agreement, dated as of September 28, 2020, by and between Tellurian Management Services LLC and Octávio Simões (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.24 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2021)
19.1*	Insider Trading Policy of Tellurian Inc.
21.1*	Subsidiaries of Tellurian Inc.
22.1*	Affiliate Securities Pledged as Collateral for Securities of Tellurian Inc.
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2*	Certification by President required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.3*	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1**	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by President pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.3**	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1*	Tellurian Inc. Dodd-Frank Clawback Policy
99.1*	Summary Reserves Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	Inline 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

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- * Filed herewith.
 - ** Furnished herewith.
 - † Management contract or compensatory plan or arrangement.
 - †† Portions of this exhibit have been omitted in accordance with Item 601(b)(10) of Regulation S-K. The omitted information is not material, and the registrant treats such information as private and confidential. The registrant hereby agrees to furnish supplementally an unredacted copy of this exhibit to the Securities and Exchange Commission upon request.
 - ‡ Certain schedules or similar attachments to this exhibit have been omitted in accordance with Item 601(a)(5) of Regulation S-K. The registrant hereby agrees to furnish supplementally to the Securities and Exchange Commission upon request a copy of any omitted schedule or attachment to this exhibit.

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.

TELLURIAN INC.

Date: February 23, 2024 By: /s/ Simon G. Oxley
Simon G. Oxley
Chief Financial Officer
(as Principal Financial Officer)
Tellurian Inc.

Date: February 23, 2024 By: /s/ Khaled A. Sharafeldin
Khaled A. Sharafeldin
Chief Accounting Officer
(as Principal Accounting Officer)
Tellurian Inc.

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

/s/ Octávio M.C. Simões Date: February 23, 2024

Chief Executive Officer, Tellurian Inc. (as co-Principal Executive Officer)

/s/ Daniel A. Belhumeur Date: February 23, 2024

President, Tellurian Inc. (as co-Principal Executive Officer)

/s/ Simon G. Oxley Date: February 23, 2024

Simon G. Oxley, Chief Financial Officer, Tellurian Inc. (as Principal Financial Officer)

/s/ Khaled A. Sharafeldin Date: February 23, 2024

Khaled A. Sharafeldin, Chief Accounting Officer, Tellurian Inc. (as Principal Accounting Officer)

/s/ Martin J. Houston Date: February 23, 2024

Martin J. Houston, Director and Chairman, Tellurian Inc.

/s/ Jean P. Abiteboul Date: February 23, 2024

Jean P. Abiteboul, Director, Tellurian Inc.

/s/ Diana Derycz-Kessler Date: February 23, 2024

Diana Derycz-Kessler, Director, Tellurian Inc.

/s/ Dillon J. Ferguson Date: February 23, 2024

Dillon J. Ferguson, Director, Tellurian Inc.

/s/ Jonathan S. Gross Date: February 23, 2024

Jonathan S. Gross, Director, Tellurian Inc.

/s/ Brooke A. Peterson Date: February 23, 2024

Brooke A. Peterson, Director, Tellurian Inc.

/s/ Don A. Turkleson Date: February 23, 2024

Don A. Turkleson, Director, Tellurian Inc.

MANAGEMENT TEAM

Martin Houston

Executive Chairman

Daniel Belhumeur

President, Tellurian Inc.

Samik Mukherjee

President, Tellurian Investments

Simon Oxley

Executive Vice President and
Chief Financial Officer

Meredith Mouer

Executive Vice President, General
Counsel and Corporate Secretary

Tarek Souki

Executive Vice President, Commercial

Joi Lecznar

Executive Vice President,
Public and Government Affairs

Margery Harris

Executive Vice President and
Chief Administrative Officer

Anita Odedra

Executive Vice President,
LNG Marketing

Mark Evans

Executive Vice President,
US LNG Marketing and Gas Supply

BUSINESS DESCRIPTION

Tellurian intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide.

Tellurian is developing a portfolio of LNG marketing and infrastructure assets that includes an ~ 27.6 mtpa LNG export facility and an associated pipeline. Tellurian is based in Houston, Texas, and its common stock is listed on the NYSE American under the symbol "TELL".

BOARD OF DIRECTORS

Martin Houston

Chairman of the Board

Jean Abiteboul

Chief Executive Officer, JA Energy
Consulting

Diana Derycz-Kessler

Principal, Bristol Capital Advisors, LLC

Dillon Ferguson

Partner, Pillsbury Winthrop Shaw
Pittman LLP

Jonathan Gross

Consultant, Jexco LLC

Don Turkleson

Director, Tellurian Inc.

CONTACTS AND ADVISORS

Independent Accountants

Deloitte & Touche LLP

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Houston, Texas 77002

Transfer Agent

Broadridge Corporate Issuer Solutions, Inc.

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Fax: +1 215 553 5402

Stock exchange ticker symbol
NYSE American: **TELL**

OFFICE INFORMATION

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