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 001-16383

CHENIERE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**95-4352386**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

845 Texas Avenue, Suite 1250

Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(713) 375-5000

(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, $ 0.003 par value	**LNG**	**New York Stock Exchange**

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

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

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

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

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period 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 registrant's Common Stock held by non-affiliates of the registrant was approximately $36.5 billion as of June 30, 2023.

As of February 16, 2024, the issuer had 234,692,274 shares of Common Stock outstanding.

Documents incorporated by reference: The definitive proxy statement for the registrant's Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant's fiscal year) is incorporated by reference into Part III.

CHENIERE ENERGY, INC.

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DEFINITIONS

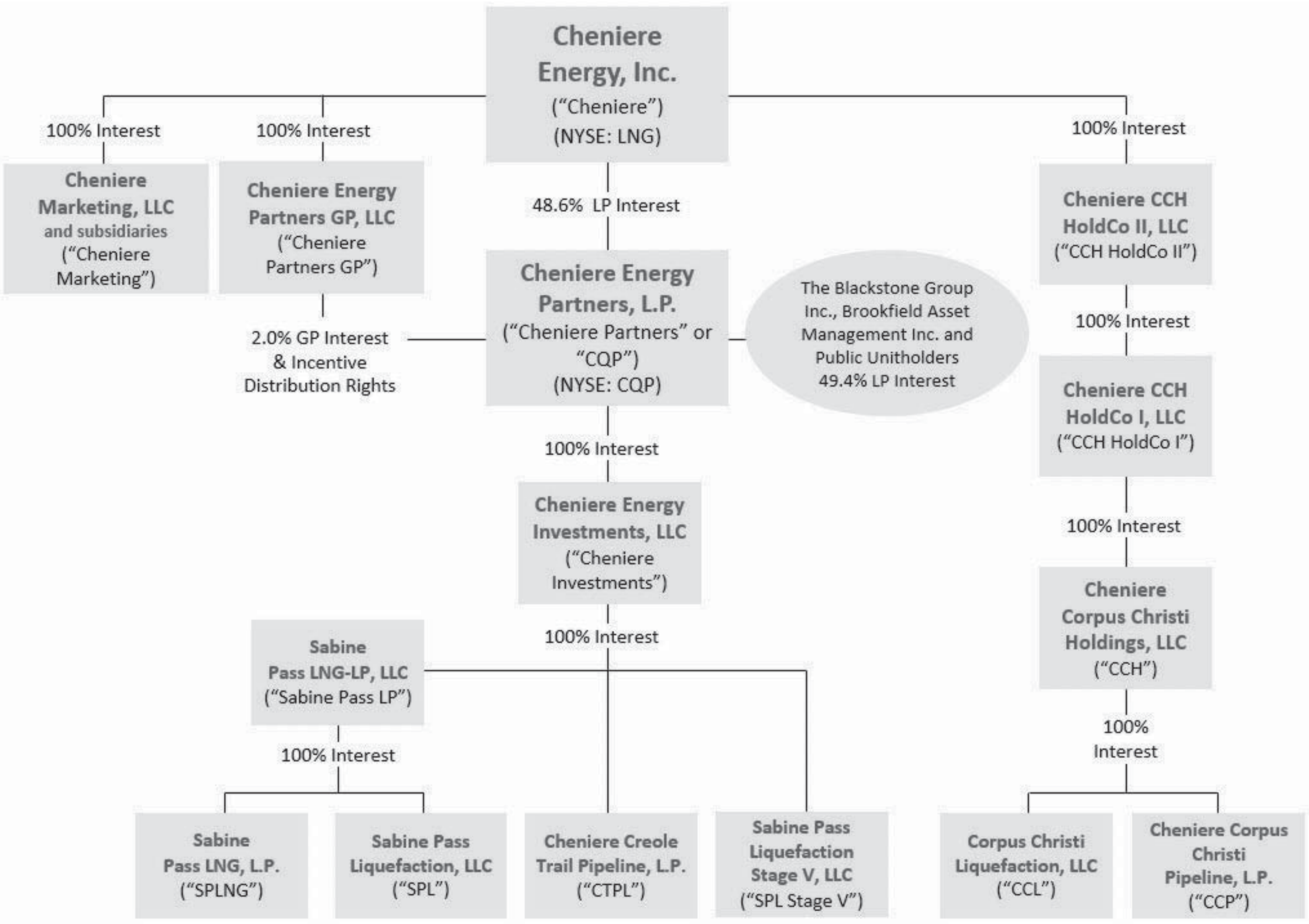
As used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

ASU	Accounting Standards Update
AFSI	adjusted financial statement income
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bcf/yr	billion cubic feet per year
Bcfe	billion cubic feet equivalent
CAMT	corporate alternative minimum tax
DAT	delivered at terminal
DOE	U.S. Department of Energy
EPC	engineering, procurement and construction
ESG	environmental, social and governance
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FID	final investment decision
FOB	free-on-board
FTA countries	countries with which the United States has a free trade agreement providing for national treatment for trade in natural gas
GAAP	generally accepted accounting principles in the United States
Henry Hub	the final settlement price (in U.S. dollars per MMBtu) for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which a relevant cargo's delivery window is scheduled to begin
IPM agreements	integrated production marketing agreements in which the gas producer sells to us gas on a global LNG or natural gas index price, less a fixed liquefaction fee, shipping and other costs
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas, a product of natural gas that, through a refrigeration process, has been cooled to a liquid state, which occupies a volume that is approximately 1/600th of its gaseous state
MMBtu	million British thermal units; one British thermal unit measures the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit
mtpa	million tonnes per annum
non-FTA countries	countries with which the United States does not have a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
SEC	U.S. Securities and Exchange Commission
SOFR	Secured Overnight Financing Rate
SPA	LNG sale and purchase agreement
TBtu	trillion British thermal units; one British thermal unit measures the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit
Train	an industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
TUA	terminal use agreement

Abbreviated Legal Entity Structure

The following diagram depicts our abbreviated legal entity structure as of December 31, 2023, including our ownership of certain subsidiaries, and the references to these entities used in this annual report:



Unless the context requires otherwise, references to "Cheniere," the "Company," "we," "us" and "our" refer to Cheniere Energy, Inc. and its consolidated subsidiaries, including our publicly traded subsidiary, CQP.

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, "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 or present facts or conditions, included herein or incorporated herein by reference are "forward-looking statements." Included among "forward-looking statements" are, among other things:

- statements that we expect to commence or complete construction of our proposed LNG terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions or portions thereof, by certain dates, or at all;
- statements regarding future levels of domestic and international natural gas production, supply or consumption or future levels of LNG imports into or exports from North America and other countries worldwide or purchases of natural gas, regardless of the source of such information, or the transportation or other infrastructure or demand for and prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or our ability to enter into such transactions;
- statements relating to Cheniere's capital deployment, including intent, ability, extent and timing of capital expenditures, debt repayment, dividends, share repurchases and execution on the capital allocation plan;
- statements regarding our future sources of liquidity and cash requirements;
- statements relating to the construction of our Trains and pipelines, including statements concerning the engagement of any EPC contractor or other contractor and the anticipated terms and provisions of any agreement with any EPC or other contractor, and anticipated costs related thereto;
- statements regarding any SPA or other agreement to be entered into or performed substantially in the future, including any revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total LNG regasification, natural gas liquefaction or storage capacities that are, or may become, subject to contracts;
- statements regarding counterparties to our commercial contracts, construction contracts and other contracts;
- statements regarding our planned development and construction of additional Trains or pipelines, including the financing of such Trains or pipelines;
- statements that our Trains, when completed, will have certain characteristics, including amounts of liquefaction capacities;
- statements regarding our business strategy, our strengths, our business and operation plans or any other plans, forecasts, projections, or objectives, including anticipated revenues, capital expenditures, maintenance and operating costs and cash flows, any or all of which are subject to change;
- statements regarding legislative, governmental, regulatory, administrative or other public body actions, approvals, requirements, permits, applications, filings, investigations, proceedings or decisions;
- statements regarding our anticipated LNG and natural gas marketing activities;
- any other statements that relate to non-historical or future information; and
- other factors described in Item 1A. Risk Factors in this Annual Report on Form 10-K.

All of these types of statements, other than statements of historical or present facts or conditions, are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "achieve," "anticipate," "believe," "contemplate," "continue," "estimate," "expect," "intend," "plan," "potential," "predict," "project," "pursue," "target," the negative of such terms or other comparable terminology. The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe that such estimates are reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond our control. In addition, assumptions may prove to be inaccurate. We caution that the forward-looking statements contained in this annual report are not guarantees of future performance and that such statements may not be realized or the forward-looking statements or events may not occur. Actual results may differ materially from those anticipated or implied in forward-looking statements as a result of a variety of factors described in this annual report and in the other reports and other information that we file with the SEC. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to update or revise any forward-looking statement or provide reasons why actual results may differ, whether as a result of new information, future events or otherwise.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

Cheniere, a Delaware corporation, is a Houston-based energy infrastructure company primarily engaged in LNG-related businesses. We provide clean, secure and affordable LNG to integrated energy companies, utilities and energy trading companies around the world. We aspire to conduct our business in a safe and responsible manner, delivering a reliable, competitive and integrated source of LNG to our customers.

LNG is natural gas (methane) in liquid form. The LNG we produce is shipped all over the world, turned back into natural gas (called "regasification") and then transported via pipeline to homes and businesses and used as an energy source that is essential for heating, cooking, other industrial uses and back up for intermittent energy sources. Natural gas is a cleaner-burning, abundant and affordable source of energy. When LNG is converted back to natural gas, it can be used instead of coal, which reduces the amount of pollution traditionally produced from burning fossil fuels, like sulfur dioxide and particulate matter that enters the air we breathe. Additionally, compared to coal, it produces significantly fewer carbon emissions. By liquefying natural gas, we are able to reduce its volume by 600 times so that we can load it onto special LNG carriers designed to keep the LNG cold and in liquid form for efficient transport overseas.

We are the largest producer of LNG in the United States and the second largest LNG operator globally, based on the total production capacity of our liquefaction facilities, which totals approximately 45 mtpa as of December 31, 2023.

We own and operate a natural gas liquefaction and export facility located in Cameron Parish, Louisiana at Sabine Pass (the **"Sabine Pass LNG Terminal"**), one of the largest LNG production facilities in the world, through our ownership interest in and management agreements with CQP, which is a publicly traded limited partnership that we formed in 2007. As of December 31, 2023, we owned 100% of the general partner interest, a 48.6% limited partner interest and 100% of the incentive distribution rights of CQP. The Sabine Pass LNG Terminal has six operational Trains, for a total production capacity of approximately 30 mtpa of LNG (the **"SPL Project"**). The Sabine Pass LNG Terminal also has operational regasification facilities that include five LNG storage tanks with aggregate capacity of approximately 17 Bcfe and vaporizers with regasification capacity of approximately 4 Bcf/d, as well as three marine berths, two of which can accommodate vessels with nominal capacity of up to 266,000 cubic meters and the third berth which can accommodate vessels with nominal capacity of up to 200,000 cubic meters. We also own and operate through CTPL, a subsidiary of CQP, a 94-mile natural gas supply pipeline that interconnects the Sabine Pass LNG Terminal with several interstate and intrastate pipelines (the **"Creole Trail Pipeline"**).

Additionally, we own and operate a natural gas liquefaction and export facility located near Corpus Christi, Texas (the **"Corpus Christi LNG Terminal"**) through CCL, which has natural gas liquefaction facilities consisting of three operational Trains for a total production capacity of approximately 15 mtpa of LNG, three LNG storage tanks with aggregate capacity of approximately 10 Bcfe and two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters. We are constructing an expansion of the Corpus Christi LNG Terminal (the **"Corpus Christi Stage 3 Project"**) for seven midscale Trains with an expected total production capacity of over 10 mtpa of LNG. We also own and operate through CCP a 21.5-mile natural gas supply pipeline that interconnects the Corpus Christi LNG Terminal with several interstate and intrastate natural gas pipelines (the **"Corpus Christi Pipeline"** and together with the Trains, storage tanks, and marine berths at the Corpus Christi LNG Terminal and the Corpus Christi Stage 3 Project, the **"CCL Project"**).

Our long-term customer arrangements form the foundation of our business and provide us with significant, stable, long-term cash flows. We have contracted substantially all of our anticipated production capacity under SPAs, in which our customers are generally required to pay a fixed fee with respect to the contracted volumes irrespective of their election to cancel or suspend deliveries of LNG cargoes, and under IPM agreements, in which the gas producer sells natural gas to us on a global LNG or natural gas index price, less a fixed liquefaction fee, shipping and other costs. The SPAs also have a variable fee component, which is generally structured to cover the cost of natural gas purchases, transportation and liquefaction fuel consumed to produce LNG. Since we procure most of our feedstock for LNG production from the U.S., the structure of these contracts helps limit our exposure to fluctuations in U.S. natural gas prices. Through our SPAs and IPM agreements, we have contracted approximately 95% of the total anticipated production from the SPL Project and the CCL Project (collectively, the **"Liquefaction Projects"**) through the mid-2030s with approximately 16 years of weighted average remaining life as of

December 31, 2023, excluding volumes from contracts with terms less than 10 years and volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation. We also market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL through our integrated marketing function.

We remain focused on safety, operational excellence and customer satisfaction. Increasing demand for LNG has allowed us to expand our liquefaction infrastructure in a financially disciplined manner. We have increased available liquefaction capacity at our Liquefaction Projects as a result of debottlenecking and other optimization projects. We believe these factors provide a foundation for additional growth in our portfolio of customer contracts in the future. We hold significant land positions at both the Sabine Pass LNG Terminal and the Corpus Christi LNG Terminal, which provide opportunity for further liquefaction capacity expansion. In March 2023, certain of our subsidiaries submitted an application with the FERC under the Natural Gas Act (the **"NGA"**) for an expansion adjacent to the CCL Project consisting of two midscale Trains with an expected total production capacity of approximately 3 mtpa of LNG (the **"CCL Midscale Trains 8 & 9 Project"**). Additionally, in May 2023, certain subsidiaries of CQP entered the pre-filing review process with the FERC under the National Environmental Policy Act (**"NEPA"**) for an expansion adjacent to the SPL Project with a potential production capacity of up to approximately 20 mtpa of total LNG capacity, inclusive of estimated debottlenecking opportunities (the **"SPL Expansion Project"**). The development of the CCL Midscale Trains 8 & 9 Project, the SPL Expansion Project or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, acceptable commercial and financing arrangements before we make a positive FID.

Our Business Strategy

Our primary business strategy is to be a full-service LNG provider to worldwide end-use customers. We accomplish this objective by owning, constructing and operating LNG and natural gas infrastructure facilities to meet our long-term customers' energy demands and:

- safely, efficiently and reliably operating and maintaining our assets;
- procuring natural gas and pipeline transport capacity to our facilities;
- providing value to our customers through destination flexibility, options not to lift cargoes and diversity of price and geography;
- continuing to secure long-term customer contracts to support our planned expansion, including the FID of potential expansion projects beyond the Corpus Christi Stage 3 Project;
- completing our construction projects safely, on-time and on-budget;
- maximizing the production of LNG to serve our customers and generating steady and stable revenues and operating cash flows;
- maintaining a flexible capital structure to finance the acquisition, development, construction and operation of the energy assets needed to supply our customers;
- executing our "all of the above" capital allocation strategy, focused on strengthening our balance sheet, funding financially disciplined growth and returning capital to our stockholders; and
- strategically identifying actionable and economic environmental solutions.

Our Business

We shipped our first LNG cargo in February 2016 and as of February 16, 2024, approximately 3,280 cumulative LNG cargoes totaling over 225 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Projects. Our LNG has been shipped to 39 countries and regions around the world.

Below is a discussion of our operations. For further discussion of our contractual obligations and cash requirements related to these operations, refer to Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Sabine Pass LNG Terminal

Liquefaction Facilities and Expansion Project

The Sabine Pass LNG Terminal, as described above under the caption General, is one of the largest LNG production facilities in the world with six Trains, five storage tanks and three marine berths. Additionally, in May 2023, certain subsidiaries of CQP entered the pre-filing review process with the FERC under the NEPA for the SPL Expansion Project.

The following summarizes the volumes of natural gas for which we have received approvals from the FERC to site, construct and operate the Trains at the SPL Project and the orders we have received from the DOE authorizing the export of domestically produced LNG by vessel from the Sabine Pass LNG Terminal through December 31, 2050:

	FERC Approved Volume		DOE Approved Volume	
	(in Bcf/yr)	*(in mtpa)*	*(in Bcf/yr)*	*(in mtpa)*
FTA countries	1,661.94	33	1,661.94	33
Non-FTA countries	1,661.94	33	1,661.94	33

Natural Gas Supply, Transportation and Storage

SPL has secured natural gas feedstock for the SPL Project through long-term natural gas supply agreements, including an IPM agreement. SPL Stage V has also entered into an IPM agreement to supply the SPL Expansion Project, subject to Cheniere making a positive FID on the first train of the SPL Expansion Project. Additionally, to ensure that SPL is able to transport natural gas feedstock to the SPL Project and manage inventory levels, it has entered into firm pipeline transportation and storage contracts with third parties and CTPL.

Regasification Facilities

The Sabine Pass LNG Terminal, as described above under the caption General, has operational regasification capacity of approximately 4 Bcf/d and aggregate LNG storage capacity of approximately 17 Bcfe. SPLNG has a long-term, third party TUA for 1 Bcf/d with TotalEnergies Gas & Power North America, Inc. (**"TotalEnergies"**), under which TotalEnergies is required to pay fixed monthly fees, whether or not it uses the regasification capacity it has reserved. Prior to its cancellation effective December 31, 2022, SPLNG also had a TUA for 1 Bcf/d with Chevron U.S.A. Inc. (**"Chevron"**). Approximately 2 Bcf/d of the remaining capacity has been reserved under a TUA by SPL, which also has a partial TUA assignment agreement with TotalEnergies, as further described in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Corpus Christi LNG Terminal

Liquefaction Facilities and Expansion Projects

The Corpus Christi LNG Terminal, as described above under the caption General, includes three Trains, three storage tanks, two marine berths and the construction of the Corpus Christi Stage 3 Project with seven midscale Trains. Additionally, in March 2023, certain of our subsidiaries submitted an application with the FERC under the NGA for the CCL Midscale Trains 8 & 9 Project.

The following table summarizes the project completion and construction status of the Corpus Christi Stage 3 Project as of December 31, 2023:

Overall project completion percentage	51.4%
Completion percentage of:	
Engineering	83.7%
Procurement	72.2%
Subcontract work	66.9%
Construction	11.1%
Date of expected substantial completion	2Q/3Q 2025 - 2H 2026

The following summarizes the volumes of natural gas for which we have received approvals from the FERC to site, construct and operate the Trains at the CCL Project and the orders we have received from the DOE authorizing the export of domestically produced LNG by vessel from the Corpus Christi LNG Terminal through December 31, 2050:

	FERC Approved Volume		DOE Approved Volume	
	(in Bcf/yr)	*(in mtpa)*	*(in Bcf/yr)*	*(in mtpa)*
Trains 1 through 3 of the CCL Project:				
FTA countries	875.16	17	875.16	17
Non-FTA countries	875.16	17	875.16	17
Corpus Christi Stage 3 Project:				
FTA countries	582.14	11.45	582.14	11.45
Non-FTA countries	582.14	11.45	582.14	11.45

Natural Gas Supply, Transportation and Storage

CCL has secured natural gas feedstock for the Corpus Christi LNG Terminal through long-term natural gas supply agreements, including IPM agreements. Additionally, to ensure that CCL is able to transport and manage the natural gas feedstock to the Corpus Christi LNG Terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation and storage capacity from third parties and CCP.

Marketing

We market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL to other customers through Cheniere Marketing, our integrated marketing function. We have, and continue to develop, a portfolio of long-, medium- and short-term SPAs to transport and deliver commercial LNG cargoes to locations worldwide.

Customers

The concentration of our customer credit risk in excess of 10% of total revenues was as follows:

	Percentage of Total Revenues from External Customers		
	Year Ended December 31,		
	2023	2022	2021
BG Gulf Coast LNG, LLC and affiliates	*	*	12%
Naturgy LNG GOM, Limited	*	*	12%
Korea Gas Corporation	*	*	10%

* Less than 10%

All of the above customers contribute to our LNG revenues through SPA contracts.

Additional information regarding our customer contracts can be found in Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 21—Customer Concentration of our Notes to Consolidated Financial Statements.

Governmental Regulation

Our LNG terminals and pipelines are subject to extensive regulation under federal, state and local statutes, rules, regulations and laws. These laws require that we engage in consultations with appropriate federal and state agencies and that we obtain and maintain applicable permits and other authorizations. These rigorous regulatory requirements increase the cost of construction and operation, and failure to comply with such laws could result in substantial penalties and/or loss of necessary authorizations.

Federal Energy Regulatory Commission

The design, construction, operation, maintenance and expansion of our liquefaction facilities, the import or export of LNG and the purchase and transportation of natural gas in interstate commerce through our pipelines (including our Creole

Trail Pipeline and Corpus Christi Pipeline) are highly regulated activities subject to the jurisdiction of the FERC pursuant to the NGA. Under the NGA, the FERC's jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale for resale of natural gas in interstate commerce, to natural gas companies engaged in such transportation or sale and to the construction, operation, maintenance and expansion of LNG terminals and interstate natural gas pipelines.

The FERC's authority to regulate interstate natural gas pipelines and the services that they provide generally includes regulation of:

- rates and charges, and terms and conditions for natural gas transportation, storage and related services;
- the certification and construction of new facilities and modification of existing facilities;
- the extension and abandonment of services and facilities;
- the administration of accounting and financial reporting regulations, including the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

Under the NGA, our pipelines are not permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service to any shipper, including our own marketing affiliates. Those rates, terms and conditions must be public, and on file with the FERC. In contrast to pipeline regulation, the FERC does not require LNG terminal owners to provide open-access services at cost-based or regulated rates. Although the provisions that codified the FERC's policy in this area expired on January 1, 2015, we see no indication that the FERC intends to change its policy in this area. On February 18, 2022, the FERC updated its 1999 Policy Statement on certification of new interstate natural gas facilities and the framework for the FERC's decision-making process, modifying the standards that the FERC uses to evaluate applications to include, among other things, reasonably foreseeable greenhouse gas (**"GHG"**) emissions that may be attributable to the project and the project's impact on environmental justice communities. On March 24, 2022, the FERC rescinded the Policy Statement, re-issued it as a draft and it remains pending. At this time, we do not expect it to have a material adverse effect on our operations.

We are permitted to make sales of natural gas for resale in interstate commerce pursuant to a blanket marketing certificate granted by the FERC with the issuance of our Certificate of Public Convenience and Necessity to our marketing affiliates. Our sales of natural gas will be affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation.

In order to site, construct and operate our LNG terminals, we received and are required to maintain authorizations from the FERC under Section 3 of the NGA as well as other material governmental and regulatory approvals and permits. The Energy Policy Act of 2005 (the **"EPAct"**) amended Section 3 of the NGA to establish or clarify the FERC's exclusive authority to approve or deny an application for the siting, construction, expansion or operation of LNG terminals, unless specifically provided otherwise in the EPAct amendments to the NGA. For example, nothing in the EPAct amendments to the NGA were intended to affect otherwise applicable law related to any other federal agency's authorities or responsibilities related to LNG terminals or those of a state acting under federal law.

In March 2023, certain of our subsidiaries submitted an application with the FERC under the NGA for the CCL Midscale Trains 8 & 9 Project. In May 2023, certain subsidiaries of CQP entered the pre-filing review process with the FERC under the NEPA for the SPL Expansion Project.

The FERC's Standards of Conduct apply to interstate pipelines that conduct transmission transactions with an affiliate that engages in natural gas marketing functions. The general principles of the FERC Standards of Conduct are: (1) independent functioning, which requires transmission function employees to function independently of marketing function employees; (2) no-conduit rule, which prohibits passing transmission function information to marketing function employees; and (3) transparency, which imposes posting requirements to detect undue preference due to the improper disclosure of non-public transmission function information. We have established the required policies, procedures and training to comply with the FERC's Standards of Conduct.

All of our FERC construction, operation, reporting, accounting and other regulated activities are subject to audit by the FERC, which may conduct routine or special inspections and issue data requests designed to ensure compliance with FERC rules, regulations, policies and procedures. The FERC's jurisdiction under the NGA allows it to impose civil and criminal penalties for any violations of the NGA and any rules, regulations or orders of the FERC up to approximately $1.3 million per day per violation, including any conduct that violates the NGA's prohibition against market manipulation.

Several other governmental and regulatory approvals and permits are required throughout the life of our LNG terminals and our pipelines. In addition, our FERC orders require us to comply with certain ongoing conditions, reporting obligations and maintain other regulatory agency approvals throughout the life of our facilities. For example, throughout the life of our LNG terminals and our pipelines, we are subject to regular reporting requirements to the FERC, the Department of Transportation's (**"DOT"**) Pipeline and Hazardous Materials Safety Administration (**"PHMSA"**) and applicable federal and state regulatory agencies regarding the operation and maintenance of our facilities. To date, we have been able to obtain and maintain required approvals as needed, and the need for these approvals and reporting obligations has not materially affected our construction or operations.

DOE Export Licenses

The DOE has authorized the export of domestically produced LNG by vessel from the Sabine Pass LNG Terminal, as discussed in *Sabine Pass LNG Terminal—Liquefaction Facilities,* and the Corpus Christi LNG Terminal, as discussed in *Corpus Christi LNG Terminal—Liquefaction Facilities.* Although it is not expected to occur, the loss of an export authorization could be a force majeure event under our SPAs.

Under Section 3 of the NGA, applications for exports of natural gas to FTA countries, which allow for national treatment for trade in natural gas, are "deemed to be consistent with the public interest" and shall be granted by the DOE without "modification or delay." FTA countries currently recognized by the DOE for exports of LNG include Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. FTAs with Israel and Costa Rica do not require national treatment for trade in natural gas. Applications for export of LNG to non-FTA countries are considered by the DOE in a notice and comment proceeding whereby the public and other interveners are provided the opportunity to comment and may assert that such authorization would not be consistent with the public interest. In January 2024, the Biden Administration announced a temporary pause on pending decisions on exports of LNG to non-FTA countries until the DOE can update the underlying analyses for authorizations. We do not believe such a pause will have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, or liquidity. The CCL Midscale Trains 8 & 9 Project is currently our only project pending non-FTA export approval with the DOE, although such approval is first subject to the receipt of regulatory permit approval from the FERC, responsive to our formal application in March 2023. We would anticipate seeking non-FTA export authorization from the DOE on the SPL Expansion Project in the future, having entered the pre-filing review process with the FERC in May 2023. See *Sabine Pass LNG Terminal* and *Corpus Christi LNG Terminal* sections above for FERC and DOE approved volumes on our existing Liquefaction Projects.

Pipeline and Hazardous Materials Safety Administration

Our LNG terminals as well as the Creole Trail Pipeline and the Corpus Christi Pipeline are subject to regulation by PHMSA. PHMSA is authorized by the applicable pipeline safety laws to establish minimum safety standards for certain pipelines and LNG facilities. The regulatory standards PHMSA has established are applicable to the design, installation, testing, construction, operation, maintenance and management of natural gas and hazardous liquid pipeline facilities and LNG facilities that affect interstate or foreign commerce. PHMSA has also established training, worker qualification and reporting requirements.

PHMSA performs inspections of pipeline and LNG facilities and has authority to undertake enforcement actions, including issuance of civil penalties up to approximately $266,000 per day per violation, with a maximum administrative civil penalty of approximately $2.7 million for any related series of violations.

Other Governmental Permits, Approvals and Authorizations

Construction and operation of the Sabine Pass LNG Terminal and the Corpus Christi LNG Terminal require additional permits, orders, approvals and consultations to be issued by various federal and state agencies, including the DOT, U.S. Army

Corps of Engineers (**"USACE"**), U.S. Department of Commerce, National Marine Fisheries Service, U.S. Department of the Interior, U.S. Fish and Wildlife Service, the U.S. Environmental Protection Agency (the **"EPA"**), U.S. Department of Homeland Security, the Louisiana Department of Environmental Quality (the **"LDEQ"**), the Texas Commission on Environmental Quality (**"TCEQ"**) and the Railroad Commission of Texas.

The USACE issues its permits under the authority of the Clean Water Act (**"CWA"**) (Section 404) and the Rivers and Harbors Act (Section 10). The EPA administers the Clean Air Act (**"CAA"**), and has delegated authority to the TCEQ and LDEQ to issue the Title V Operating Permit and the Prevention of Significant Deterioration Permit. These two permits are issued by the LDEQ for the Sabine Pass LNG Terminal and CTPL and by the TCEQ for the CCL Project.

*Commodity Futures Trading Commission (**"CFTC"**)*

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the **"Dodd-Frank Act"**) amended the Commodity Exchange Act to provide for federal regulation of the over-the-counter derivatives market and entities, such as us, that participate in those markets. The CFTC has enacted a number of regulations pursuant to the Dodd-Frank Act, including the speculative position limit rules. Given the enactment of the speculative position limit rules, as well as the impact of other rules and regulations under the Dodd-Frank Act, the impact of such rules and regulations on our business continues to be uncertain, but is not expected to be material.

As required by the Dodd-Frank Act, the CFTC and federal banking regulators also adopted rules requiring swap dealers (as defined in the Dodd-Frank Act), including those that are regulated financial institutions, to collect initial and/or variation margin with respect to uncleared swaps from their counterparties that are financial end users, registered swap dealers or major swap participants. These rules do not require collection of margin from non-financial-entity end users who qualify for the end user exception from the mandatory clearing requirement or from non-financial end users or certain other counterparties in certain instances. We qualify as a non-financial-entity end user with respect to the swaps that we enter into to hedge our commercial risks.

Pursuant to the Dodd-Frank Act, the CFTC adopted additional anti-manipulation and anti-disruptive trading practices regulations that prohibit, among other things, manipulative, deceptive or fraudulent schemes or material misrepresentation in the futures, options, swaps and cash markets. In addition, separate from the Dodd-Frank Act, our use of futures and options on commodities is subject to the Commodity Exchange Act and CFTC regulations, as well as the rules of futures exchanges on which any of these instruments are executed. Should we violate any of these laws and regulations, we could be subject to a CFTC or an exchange enforcement action and material penalties, possibly resulting in changes in the rates we can charge.

United Kingdom / European Regulations

Our European trading activities, which are primarily established in and operated out of the United Kingdom (**"U.K."**), are subject to a number of European Union (**"EU"**) and U.K. laws and regulations, including but not limited to:

- the European Market Infrastructure Regulation, which was designed to increase the transparency and stability of the European Economic Area (**"EEA"**) derivatives markets;
- the Regulation on Wholesale Energy Market Integrity and Transparency, which prohibits market manipulation and insider trading in EEA wholesale energy markets and imposes various transparency and other obligations on participants active in these markets;
- the Markets in Financial Instruments Directive and Regulation (**"MiFID II"**), which sets forth a financial services framework across the EEA, including rules for firms engaging in investment services and activities in connection with certain financial instruments, including a range of commodity derivatives; and
- the Market Abuse Regulation, which was implemented to create an enhanced market abuse framework, and which applies generally to all financial instruments listed or traded on EEA trading venues (**"Traded Instruments"**) as well as other over-the-counter financial instruments priced on, or impacting, the price or value of the Traded Instrument.

Following the U.K.'s departure from the EU (**"Brexit"**), the EU-wide rules that applied to the U.K. while it was a member of the EU (and during the transition period) have been replicated, subject to certain amendments, to create a parallel set of rules applicable only in the U.K. As a result, we are subject to two sets of substantively similar rules based on the same underlying legislation: (i) one set of rules that apply in the EEA (i.e. not including the U.K.) (the **"EEA Rules"**); and (ii) one set of rules that apply only in the U.K. (the **"U.K. Onshored Rules"**).

To the extent our trading activities have a nexus with the EEA, we comply with the EEA Rules. However, as our trading activities are primarily operated out of the U.K., the main rules that impact and apply to us on a day-to-day basis are the U.K. Onshored Rules.

In particular, under the U.K. Onshored Rules, firms engaging in investment services and activities under U.K. MiFID II must be authorized unless an exemption applies. We meet the criteria for an exemption and therefore do not need to be authorized under U.K. MiFID II.

In addition to the U.K. Onshored Rules, we are also subject to a separate, U.K.-specific regime that is not based on prior EU/EEA legislation. This is primarily set out in the U.K.'s Financial Services and Markets Act 2000 (**"FSMA"**) and Financial Services and Markets Act 2000 (Regulated Activities) Order 2001 (**"RAO"**), which, among other things, governs the regulation of financial services and markets in the U.K., and contains a definitive list of the specified kinds of activities and products that are regulated. Under these U.K.-specific rules, a firm engaging in regulated activities must be authorized unless an exclusion applies. We qualify under applicable exclusions and therefore are not required to be authorized under the U.K. FSMA/RAO regime.

In December 2022, the EU enacted regulations, which among other things established a market correction mechanism against excessively high LNG prices and provided for the collection of information though new reporting obligations that would be utilized to provide for a new LNG pricing assessment/benchmark. The applicable regulations are set forth in Council Regulation (EU) 2022/2576-2581. The impact of such regulations on our business remains uncertain, but is not expected to be material.

Violation of the foregoing laws and regulations could result in investigations, possible fines and penalties, and in some scenarios, criminal offenses, as well as reputational damage.

Brexit and Equivalence

As referenced above, the U.K. ceased to be a member of the EU on January 31, 2020. On December 24, 2020, the EU and the U.K. reached an agreement in principle on the terms of certain agreements and declarations governing the ongoing relationship between the EU and the U.K., including the EU-U.K. Trade and Cooperation Agreement (the **"TCA"**). The TCA is limited in its scope; in particular the TCA does not make any meaningful provision for the financial services sector. Uncertainties remain relating to certain aspects of the U.K.'s future economic, trading and legal relationships with the EU and with other countries.

The Financial Services and Markets Act 2023 (**"FSMA 2023"**) came into U.K. law in June 2023. FSMA 2023 is the framework for the U.K.'s post-Brexit financial legislative and regulatory landscape. It is intended to provide the foundations for a significant overhaul and re-structuring of the U.K. financial services and markets regimes. The changes include the revocation of retained EU laws, the introduction of new powers and objectives for the regulators of such markets, as well as a number of measures relevant to financial market infrastructure operators and market participants. Changes will be implemented pursuant to subsidiary legislation or directly by regulators. However, at this time it is not possible to determine whether any such actions would have a material impact on our business.

Environmental Regulation

Our LNG terminals are subject to various federal, state and local laws and regulations relating to the protection of the environment and natural resources. These environmental laws and regulations can affect the cost and output of operations and may impose substantial penalties for non-compliance and substantial liabilities for pollution, as further described in the risk factor *Existing and future safety, environmental and similar laws and governmental regulations could result in increased compliance costs or additional operating costs or construction costs and restrictions* in Risks Relating to Regulations within Item 1A. Risk Factors. Many of these laws and regulations, such as those noted below, restrict or prohibit impacts to the environment or the types, quantities and concentration of substances that can be released into the environment and can lead to substantial administrative, civil and criminal fines and penalties for non-compliance.

Clean Air Act

Our LNG terminals are subject to the federal CAA and comparable state and local laws. We may be required to incur certain capital expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing air emission-related issues. However, we do not believe any such requirements will have a material adverse effect on our operations, or the construction and operations of our liquefaction facilities.

On February 28, 2022, the EPA removed a stay of formaldehyde standards in the National Emission Standards for Hazardous Air Pollutants (**"NESHAP"**) Subpart YYYY for stationary combustion turbines located at major sources of hazardous air pollutant (**"HAP"**) emissions. Owners and operators of lean remix gas-fired turbines and diffusion flame gas-fired turbines at major sources of HAP that were installed after January 14, 2003 were required to comply with NESHAP Subpart YYYY by March 9, 2022 and demonstrate initial compliance with those requirements by September 5, 2022. We do not believe that the construction and operations of our liquefaction facilities will be materially and adversely affected by such regulatory actions.

We are supportive of regulations reducing GHG emissions over time. Since 2009, the EPA has promulgated and finalized multiple GHG emissions regulations related to reporting and reductions of GHG emissions from our facilities. On December 2, 2023, the EPA issued final rules to reduce methane and volatile organic compounds (**"VOC"**) emissions from new, existing and modified emission sources in the oil and gas sector. These regulations will require monitoring of methane and VOC emissions at our compressor stations. We do not believe such regulations will have a material adverse effect on our operations, financial condition or results of operations.

From time to time, Congress has considered proposed legislation directed at reducing GHG emissions. On August 16, 2022, President Biden signed H.R. 5376(P.L. 117-169), the Inflation Reduction Act of 2022 (**"IRA"**) which includes a charge on methane emissions above a certain methane intensity threshold for facilities that report their GHG emissions under the EPA's Greenhouse Gas Emissions Reporting Program Part 98 regulations. The charge starts at $900 per metric ton of methane in 2024, $1,200 per metric ton in 2025, and increasing to $1,500 per metric ton in 2026 and beyond. In January 2024, the EPA issued a proposed rule to impose and collect the methane emissions charge authorized under the IRA. We do not believe the methane charge will have a material adverse effect on our operations, financial condition or results of operations.

*Coastal Zone Management Act (**"CZMA"**)*

The siting and construction of our LNG terminals within the coastal zone is subject to the requirements of the CZMA. The CZMA is administered by the states (in Louisiana, by the Department of Natural Resources, and in Texas, by the General Land Office). This program is implemented to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas.

Clean Water Act

Our LNG terminals are subject to the federal CWA and analogous state and local laws. The CWA imposes strict controls on the discharge of pollutants into the navigable waters of the United States, including discharges of wastewater and storm water runoff and fill/discharges into waters of the United States. Permits must be obtained prior to discharging pollutants into state and federal waters. The CWA is administered by the EPA, the USACE and by the states (in Louisiana, by the LDEQ, and in Texas, by the TCEQ). The CWA regulatory programs, including the Section 404 dredge and fill permitting program and Section 401 water quality certification program carried out by the states, are frequently the subject of shifting agency interpretations and legal challenges, which at times can result in permitting delays.

*Resource Conservation and Recovery Act (**"RCRA"**)*

The federal RCRA and comparable state statutes govern the generation, handling and disposal of solid and hazardous wastes and require corrective action for releases into the environment. When such wastes are generated in connection with the operations of our facilities, we are subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes.

Protection of Species, Habitats and Wetlands

Various federal and state statutes, such as the Endangered Species Act, the Migratory Bird Treaty Act, the CWA and the Oil Pollution Act, prohibit certain activities that may adversely affect endangered or threatened animal, fish and plant species and/or their designated habitats, wetlands, or other natural resources. If one of our LNG terminals or pipelines adversely affects a protected species or its habitat, we may be required to develop and follow a plan to avoid those impacts. In that case, siting, construction or operations may be delayed or restricted and cause us to incur increased costs.

It is not possible at this time to predict how future regulations or legislation may address protection of species, habitats and wetlands and impact our business. However, we do not believe such regulatory actions will have a material adverse effect on our operations, or the construction and operations of our liquefaction facilities.

Market Factors and Competition

Market Factors

Our ability to enter into additional long-term SPAs to underpin the development of additional Trains, sell LNG through Cheniere Marketing or develop new projects is subject to market factors. These factors include changes in worldwide supply and demand for natural gas, LNG and substitute products, the relative prices for natural gas, crude oil and substitute products in North America and international markets, the extent of energy security needs in the EU and elsewhere, the rate of fuel switching for power generation from coal, nuclear or oil to natural gas and other overarching factors such as global economic growth and the pace of any transition from fossil-based systems of energy production and consumption to alternative energy sources. In addition, our ability to obtain additional funding to execute our business strategy is subject to the investment community's appetite for investment in LNG and natural gas infrastructure and our ability to access capital markets.

We expect that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to oil and coal. Market participants around the globe have shown commitments to environmental goals consistent with many policy initiatives that we believe are constructive for LNG demand and infrastructure growth. Currently, significant amounts of money are being invested across Europe, Asia and Latin America in natural gas projects under construction, and more continues to be earmarked to planned projects globally. In Europe, there are various plans to install more than 85 mtpa of import capacity over the near-term to secure access to LNG and displace Russian gas imports. In India, there are more than 11,000 kilometers of gas pipelines under construction to expand the gas distribution network and increase access to natural gas. And in China, billions of U.S. dollars have already been invested and hundreds of billions of U.S. dollars are expected to be further invested all along the natural gas value chain to enable growth and decrease harmful emissions. Furthermore, some of the existing integrated liquefaction facilities outside of the U.S. have been experiencing issues related to reduced feed gas as a result of depleting upstream resources. Global supply contributions from these plants have been decreasing and LNG supply growth is expected to help support these shortages.

As a result of these dynamics, we expect natural gas and LNG to continue to play an important role in satisfying energy demand going forward. In its forecast published in the third quarter of 2023, Wood Mackenzie Limited (**"WoodMac"**) forecasted that global demand for LNG would increase by approximately 60%, from approximately 411 mtpa, or 19.7 Tcf, in 2022, to 657 mtpa, or 31.5 Tcf, in 2040 and to 709 mtpa or 34 Tcf in 2050. In its forecast published in the third quarter of 2023, WoodMac also forecasted LNG production from existing operational facilities and new facilities already under construction would be able to supply the market with approximately 544 mtpa in 2040, declining to 477 mtpa in 2050. This could result in a market need for construction of an additional approximately 113 mtpa of LNG production by 2040 and about 231 mtpa by 2050. As a cleaner burning fuel with lower emissions than coal or liquid fuels in power generation, we expect natural gas and LNG to play a central role in balancing grids, serving as back up for intermittent energy sources and contributing to a low carbon energy system globally. We believe the capital and operating costs of the uncommitted capacity of our Liquefaction Projects, as well as our proposed expansions at Sabine Pass and Corpus Christi, are competitive with new proposed projects globally and we are well-positioned to capture a portion of this incremental market need.

We have limited exposure to oil price movements as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements indexed to Henry Hub. These agreements contain fixed fees that are required to be paid even if the customers elect to cancel or suspend delivery of LNG cargoes. Through our SPAs and IPM agreements, we have contracted approximately 95% of the total anticipated production from the Liquefaction Projects through the mid-2030s with approximately 16 years of weighted average remaining life as of December 31, 2023, excluding volumes from contracts with terms less than 10 years and volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation.

Competition

Despite the long term nature of our SPAs, when SPL, CCL or our integrated marketing function need to replace or amend any existing SPA or enter into new SPAs, they will compete with each other and other natural gas liquefaction projects throughout the world on the basis of price per contracted volume of LNG at that time. Revenues associated with any incremental volumes, including those sold by our integrated marketing function, will also be subject to market-based price competition. Many of the companies with which we compete are major energy corporations with longer operating histories, more development experience, greater name recognition, greater financial, technical and marketing resources and greater access to LNG markets than us.

Corporate Responsibility

As described in Market Factors and Competition, we expect that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to oil and coal. Our vision is to provide clean, secure and affordable energy to the world. This vision underpins our focus on responding to the world's shared energy challenges—expanding the global supply of clean, secure and affordable energy, improving air quality, reducing emissions and supporting the transition to a lower-carbon future. Our approach to corporate responsibility is guided by our Climate and Sustainability Principles: Transparency, Science, Supply Chain and Operational Excellence. In August 2023, we published *The Power of Connection*, our fourth Corporate Responsibility (**"CR"**) report, which details our approach and progress on ESG matters. Our CR report is available at www.cheniere.com/our-responsibility/reporting-center. Information on our website, including the CR report, is not incorporated by reference into this Annual Report on Form 10-K. For further discussion on social and governance matters, see Human Capital Resources.

Our climate strategy is to measure and mitigate emissions – to better position our LNG supplies to remain competitive in a lower carbon future, providing energy, economic and environmental security to our customers across the world. To maximize the environmental benefits of our LNG, we believe it is important to develop future climate goals and strategies based on an accurate and holistic assessment of the emissions profile of our LNG, accounting for all steps in the supply chain.

Consequently, we have collaborated with natural gas midstream companies, technology providers and leading academic institutions on life-cycle assessment (**"LCA"**) models, quantification, monitoring, reporting and verification (**"QMRV"**) of GHG emissions and other research and development projects. We also co-founded and sponsored the Energy Emissions Modeling and Data Lab (**"EEMDL"**), a multidisciplinary research and education initiative led by the University of Texas at Austin in collaboration with Colorado State University and the Colorado School of Mines. In addition, we commenced providing Cargo Emissions Tags (**"CE Tags"**) to our long-term customers in June 2022, and in October 2022 joined the Oil and Gas Methane Partnership (**"OGMP"**) 2.0, the United Nations Environment Programme's (**"UNEP"**) flagship oil and gas methane emissions reporting and mitigation initiative.

Our total incremental expenditures related to climate initiatives, including capital expenditures, were not material to our Consolidated Financial Statements during the years ended December 31, 2023, 2022 and 2021. However, as governments consider and implement actions to reduce GHG emissions and the transition to a lower-carbon economy continues to evolve, as described in Market Factors and Competition, we expect the scope and extent of our future climate and sustainability initiatives to evolve accordingly. While we have not incurred material direct expenditures related to climate change, we are proactive in our management of climate risks and opportunities, including compliance with existing and future government regulations. We face certain business and operational risks associated with physical impacts from climate change, such as exposure to severe weather events or changes in weather patterns, in addition to transition risks. Please see Item 1A. Risk Factors for additional discussion.

Subsidiaries

Substantially all of our assets are held by our subsidiaries. We conduct most of our business through these subsidiaries, including the development, construction and operation of our LNG terminal business and the development and operation of our LNG and natural gas marketing business.

Human Capital Resources

We are in a unique position as the first U.S. LNG company in the lower 48. As the first mover, we invest in the core human capital priorities — attracting, engaging and developing diverse talent and building an inclusive and equitable workplace — because they underpin our current and future success and ability to generate long-term value.

As of December 31, 2023, we had 1,605 full-time employees with 1,511 located in the U.S. and 94 located outside of the U.S. (primarily in the U.K.).

Our strength comes from the collective expertise of our diverse workforce and through our core values of teamwork, respect, accountability, integrity, nimble and safety ("**TRAINS**"). Our employees help drive our success, build our reputation, establish our legacy and deliver on our commitments to our customers. Through fulfilling career opportunities, training, development and a competitive compensation program, we aim to keep our employees engaged. Our voluntary turnover was 6.1% for 2023.

Our Chief Human Resources Officer oversees human capital management. This includes our approach to talent attraction and retention, rewards and remuneration, employee relations, employee engagement and training and development. Our Chief Compliance and Ethics Officer oversees the diversity, equity and inclusion ("**DEI**") program. Both officers communicate progress on our programs to our board of directors (our **"Board"**) quarterly.

Talent Attraction, Engagement and Retention

Our recruitment strategy is focused on attracting diverse and highly skilled talent. We offer competitive compensation and benefits, and work to develop and attract a strong talent pipeline through a range of internship, apprenticeship and vocational programs. We invest in opportunities to help local students and underserved communities gain specialized skills and create local jobs through sponsorship of apprenticeships and internships. On an annual basis, we participate in workforce availability studies in the geographic areas where we operate to ensure representation of the local workforce. Internally and externally, we post openings to attract individuals with a range of backgrounds, skills and experience, offering employee bonuses for referring highly qualified candidates.

We manage and measure organizational health with a view to gaining insight into employees' experiences, levels of workplace satisfaction and feelings of engagement and inclusion with the company. Employees are encouraged to share ideas and concerns through multiple feedback channels including townhalls and hotlines which can be reached anonymously. Insights from these channels are used to develop both company-wide and business unit level talent development plans and training programs.

Compensation and Benefits

We provide robust compensation and benefits programs to our employees. In addition to salaries, all employees are eligible for annual bonuses and stock awards. Benefit plans, which vary by country, include a 401(k) plan, healthcare and insurance benefits, health savings and flexible spending accounts, paid time off, family leave, family care resources, employee assistance programs and tuition assistance. We link our annual incentive program to financial and non-financial performance metrics, including but not limited to, ESG and DEI performance criteria.

Diversity, Equity and Inclusion

We are committed to supporting a diverse and inclusive culture where all employees can thrive and feel welcomed and valued. To create this environment, we are committed to equal employment opportunity and to compliance with all federal, state and local laws that prohibit workplace discrimination, harassment and unlawful retaliation. Our Code of Business Conduct and Ethics, our TRAINS values and both our discrimination and harassment and equal employment opportunity policies demonstrate our commitment to building an inclusive workplace, regardless of race, beliefs, nationality, gender and sexual orientation or any other status protected by our policy. We are committed to providing fair and equitable employee programs including compensation and benefits. We provide executives and senior management with DEI training and Unconscious Bias training to all employees. In addition, we will continue our "Values in Action" efforts, which supports employees in identifying and implementing actions and behaviors that align with our TRAINS values.

Through our strategic recruitment efforts, we attract a variety of candidates with a diversity of backgrounds, skills, experience and expertise. Since 2019, we have had a 28.4% increase in racially or ethnically diverse employees and a 42% increase in racially or ethnically diverse management. In the past five years, the percentage of female employees remained steady at 26%. In 2023, we contributed over $1 million to DEI community efforts, of which approximately $250,000 was used to fund scholarship programs for students attending historically black colleges and universities in our communities. In addition, scholarship recipients are provided the opportunity to network with employees and apply for summer internships. We also committed to other scholarships and community efforts furthering our commitment to DEI.

We encourage our employees to leverage their unique backgrounds through involvement in various employee resource groups and employee networks. Groups such as WILS (Women Inspiring Leadership Success), EPN (Emerging Professional Network), Cultural Champions Teams and MVN (Military and Veterans Network), our newest employee resource group focused on military veterans help build a culture of inclusion.

Development and Training

As the first exporter of LNG in the lower 48 of the US, we faced the unique challenge of developing our own LNG talent. Our apprenticeship program prepares local students for careers in LNG. This program combines classroom education with training and on-site learning experiences at our facilities.

We strive to provide our people with all of the tools and support necessary for them to succeed. We actively encourage our employees to take ownership of their careers and offer a number of resources to do so. Employees receive mid-year and annual performance reviews, as well as frequent informal discussions to help meet their career goals. We also conduct annual talent reviews and succession planning sessions to ensure future organizational talent trends are met. To ensure safe, reliable and efficient operations in a highly regulated environment, we offer online and site-specific learning opportunities. We also provide employees, leaders and executives with targeted development programming to solidify internal talent pipelines and succession plans.

Employee Safety, Health and Wellness

The safety of our employees, contractors and communities is one of our core values, and is carried out through our required safety programs and safety and health related procedures. Safety efforts are led by our Executive Safety Committee, which includes the Chief Executive Officer, senior leaders from across the company and representatives from our sites. We focus our efforts on continuously improving our performance. For the year ended December 31, 2023, we had zero employee recordable injuries and five contractor recordable injuries. Our total recordable incident rate (employees and contractors combined) was 0.10, placing us in the top quartile of industry benchmarks based on Bureau of Labor safety statistics.

To support the well-being of our employees, we provide a wellness program that offers employees incentives to maintain an active lifestyle and set personal wellness goals. Incentives include online education related to health, nutrition, emotional health and vaccinations, as well as subsidies for fitness devices and gym memberships. We also offer mammography screenings, rooms for nursing mothers and biometric screenings on site.

Available Information

Our common stock has been publicly traded since March 24, 2003 and is traded on the New York Stock Exchange under the symbol "LNG." Our principal executive offices are located at 845 Texas Avenue, Suite 1250, Houston, Texas 77002, and our telephone number is (713) 375-5000. Our internet address is www.cheniere.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes and is not incorporated by reference into this Form 10-K.

We will also make available to any stockholder, without charge, copies of our annual report on Form 10-K as filed with the SEC. For copies of this, or any other filing, please contact: Cheniere Energy, Inc., Investor Relations Department, 845 Texas Avenue Suite 1250, Houston, Texas 77002 or call (713) 375-5000. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers.

Additionally, we encourage you to review our CR Report (located on our internet site at www.cheniere.com), for more detailed information regarding our Human Capital programs and initiatives, as well as our initiatives and metrics related to ESG. Nothing on our website, including our CR Report or sections thereof, shall be deemed incorporated by reference into this Annual Report.

ITEM 1A. RISK FACTORS

The following are some of the important factors that should be considered when investing in us, as such risk factors could adversely affect our business, financial condition, results of operation or cash flows or have other adverse impacts, and could cause actual results to differ materially from estimates or expectations contained in our forward-looking statements. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also adversely affect our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

The risk factors in this report are grouped into the following categories:

- Risks Relating to Our Financial Matters;
- Risks Relating to Our Operations and Industry; and
- Risks Relating to Regulations.

Risks Relating to Our Financial Matters

An inability to source capital to supplement our available cash resources and existing credit facilities could cause us to have inadequate liquidity and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

As of December 31, 2023, we had, on a consolidated basis, $4.1 billion of cash and cash equivalents (of which $575 million was held by CQP), $459 million of restricted cash and cash equivalents (of which $56 million was held by CQP), a total of $7.6 billion of available commitments under our credit facilities and $23.9 billion of total debt outstanding (before unamortized discount and debt issuance costs). SPL, CQP, CCH and Cheniere operate with independent capital structures as further detailed in Note 11—Debt of our Notes to Consolidated Financial Statements. We incur, and will incur, significant interest expense relating to financing the assets at the Sabine Pass LNG Terminal and the Corpus Christi LNG Terminal, and we anticipate drawing on current committed facilities and/or incurring additional debt to finance the construction of the Corpus Christi Stage 3 Project, as well as the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project if a positive FID is made on these expansion projects. Our ability to fund our capital expenditures and refinance our indebtedness will depend on our ability to access additional project financing as well as the debt and equity capital markets. A variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, lending institutions' evolving policies on financing businesses linked to fossil fuels and the repricing of market risks and volatility in capital and financial markets. Our financing costs could increase or future borrowings or equity offerings may be unavailable to us or unsuccessful, which could cause us to be unable to pay or refinance our indebtedness or to fund our other liquidity needs. We also rely on borrowings under our credit facilities to fund our capital expenditures. If any of the lenders in the syndicates backing these facilities was unable to perform on its commitments, we may need to seek replacement financing, which may not be available as needed, or may be available in more limited amounts or on more expensive or otherwise unfavorable terms.

Our ability to generate cash is substantially dependent upon the performance by customers under long-term contracts that we have entered into, and we could be materially and adversely affected if any significant portion of our customers fails to perform its contractual obligations for any reason.

Our future results and liquidity are substantially dependent upon performance by our customers to make payments under long-term contracts. As of December 31, 2023, we had SPAs with initial terms of 10 or more years with a total of 29 different third party customers.

While substantially all of our long-term third party customer arrangements are executed with a creditworthy parent company or secured by a parent company guarantee or other form of collateral, we are nonetheless exposed to credit risk in the event of a customer default that requires us to seek recourse.

Additionally, our long-term SPAs entitle the customer to terminate their contractual obligations upon the occurrence of certain events which include, but are not limited to: (1) if we fail to make available specified scheduled cargo quantities; (2) delays in the commencement of commercial operations; and (3) under the majority of our SPAs, upon the occurrence of certain events of force majeure.

Although we have not had a history of material customer default or termination events, the occurrence of such events are largely outside of our control and may expose us to unrecoverable losses. We may not be able to replace these customer arrangements on desirable terms, or at all, if they are terminated. As a result, our business, contracts, financial condition, operating results, cash flow, liquidity and prospects could be materially and adversely affected.

Our subsidiaries may be restricted under the terms of their indebtedness from making distributions under certain circumstances, which may limit CQP's ability to pay or increase distributions to us or inhibit our access to cash flows from the CCL Project and could materially and adversely affect us.

The agreements governing our subsidiaries' indebtedness restrict payments that our subsidiaries can make to CQP or us in certain events. For example, SPL is restricted from making distributions under agreements governing its indebtedness generally unless, among other requirements, appropriate reserves have been established for debt service using cash or letters of credit and a debt service coverage ratio of 1.25:1.00 is satisfied.

CCH is restricted from making distributions under agreements governing its indebtedness generally unless, among other requirements, appropriate reserves have been established for debt service using cash or letters of credit and a debt service coverage ratio of 1.25:1.00 is satisfied. In addition, prior to completion of the Corpus Christi Stage 3 Project, CCH is also required to confirm that it has sufficient funds, including senior debt commitments, equity funding and projected contracted cash flows from the fixed price component of its third party SPAs, to meet remaining expenditures required for the Corpus Christi Stage 3 Project in order to achieve completion by a certain specified date.

Our subsidiaries' inability to pay distributions to CQP or us as a result of the foregoing restrictions in the agreements governing their indebtedness may inhibit CQP's ability to pay or increase distributions to us and its other unitholders or inhibit our access to cash flows from the CCL Project, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our efforts to manage commodity and financial risks through derivative instruments, including our IPM agreements, could adversely affect our earnings reported under GAAP and our liquidity.

We use derivative instruments to manage commodity, currency and financial market risks. The extent of our derivative position at any given time depends on our assessments of the markets for these commodities and related exposures. We currently account for our derivatives at fair value, with immediate recognition of changes in the fair value in earnings, as described in Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. Such valuations are primarily valued based on estimated forward commodity prices and are more susceptible to variability particularly when markets are volatile, which could have a significant adverse effect on our earnings reported under GAAP. For example, as described in Results of Operations in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, our net income for the year ended December 31, 2022 included $5.7 billion of losses resulting from changes in the fair values of our derivatives, of which substantially all of such losses were related to commodity derivative instruments indexed to international LNG prices, mainly our IPM agreements.

These transactions and other derivative transactions have and may continue to result in substantial volatility in results of operations reported under GAAP, particularly in periods of significant commodity, currency or financial market variability. For certain of these instruments, in the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments involves management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

In addition, our liquidity may be adversely impacted by the cash margin requirements of the commodities exchanges or the failure of a counterparty to perform in accordance with a contract. As of December 31, 2023 and 2022, we had collateral posted with counterparties by us of $18 million and $134 million, respectively, which are included in margin deposits in our Consolidated Balance Sheets.

Restrictions in agreements governing us and our subsidiaries' indebtedness may prevent us and our subsidiaries from engaging in certain beneficial transactions, which could materially and adversely affect us.

In addition to restrictions on the ability of us, CQP, SPL and CCH to make distributions or incur additional indebtedness, the agreements governing our indebtedness also contain various other covenants that may prevent us from engaging in beneficial transactions, including limitations on our ability to:

- make certain investments;
- purchase, redeem or retire equity interests;
- issue preferred stock;
- sell or transfer assets;
- incur liens;
- enter into transactions with affiliates;
- consolidate, merge, sell or lease all or substantially all of our assets; and
- enter into sale and leaseback transactions.

Any restrictions on the ability to engage in beneficial transactions could materially and adversely affect us.

Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Dividends are authorized and determined by our Board in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution;
- Our results of operations and anticipated future results of operations;
- Our financial condition, especially in relation to the anticipated future capital needs of any expansion of our Liquefaction Facilities;
- The level of distributions paid by comparable companies;
- Our operating expenses; and
- Other factors our Board deems relevant.

We expect to continue to pay quarterly dividends to our stockholders; however, our Board may reduce our dividend or cease declaring dividends at any time, including if it determines that our current or forecasted future cash flows provided by our operating activities, after deducting capital expenditures, investments and other commitments, are not sufficient to pay our desired levels of dividends to our stockholders or to pay dividends to our stockholders at all.

Additionally as of December 31, 2023, $2.1 billion of repurchase authority remained under our share repurchase program our Board had authorized. Our share repurchase program does not obligate us to acquire a specific number of shares during any period, and our decision to commence, discontinue or resume repurchases in any period will depend on the same factors that our Board may consider when declaring dividends, among others.

Any downward revision in the amount of dividends we pay to stockholders or the number of shares we purchase under our share repurchase program could have an adverse effect on the market price of our common stock.

Risks Relating to Our Operations and Industry

Catastrophic weather events or other disasters could result in an interruption of our operations, a delay in the construction of our Liquefaction Projects, damage to our Liquefaction Projects and increased insurance costs, all of which could adversely affect us.

Weather events such as major hurricanes and winter storms have caused interruptions or temporary suspension in construction or operations at our facilities or caused minor damage to our facilities. Our risk of loss related to weather events or other disasters is limited by contractual provisions in our SPAs, which can provide under certain circumstances relief from operational events, and partially mitigated by insurance we maintain. Aggregate direct and indirect losses associated with the aforementioned weather events, net of insurance reimbursements, have not historically been material to our Consolidated Financial Statements, and we believe our insurance coverages maintained, existence of certain protective clauses within our SPAs and other risk management strategies mitigate our exposure to material losses. However, future adverse weather events and collateral effects, or other disasters such as explosions, fires, floods or severe droughts, could cause damage to, or interruption of operations at our terminals or related infrastructure, which could impact our operating results, increase insurance premiums or deductibles paid and delay or increase costs associated with the construction and development of the Liquefaction Projects or our other facilities. Our LNG terminal infrastructure and LNG facilities located in or near Corpus Christi, Texas and Sabine Pass, Louisiana are designed in accordance with requirements of 49 Code of Federal Regulations Part 193, *Liquefied Natural Gas Facilities: Federal Safety Standards*, and all applicable industry codes and standards.

Disruptions to the third party supply of natural gas to our pipelines and facilities could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We depend upon third party pipelines and other facilities that provide gas delivery options to our liquefaction facilities and pipelines. If 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, failure to replace contracted firm pipeline transportation capacity on economic terms, or any other reason, our ability to receive natural gas volumes to produce LNG or to continue shipping natural gas from producing regions or to end markets could be adversely impacted. Such disruptions to our third party supply of natural gas may also be caused by weather events or other disasters described in the risk factor *Catastrophic weather events or other disasters could result in an interruption of our operations, a delay in the construction of our Liquefaction Projects, damage to our Liquefaction Projects and increased insurance costs, all of which could adversely affect us.* While certain contractual provisions in our SPAs can limit the potential impact of disruptions, and historical indirect losses incurred by us as a result of disruptions to our third party supply of natural gas have not been material, any significant disruption to our natural gas supply where we may not be protected could result in a substantial reduction in our revenues under our long-term SPAs or other customer arrangements, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We may not be able to purchase or receive physical delivery of sufficient natural gas to satisfy our delivery obligations under the SPAs, which could have a material adverse effect on us.

Under the SPAs with our customers, we are required to make available to them a specified amount of LNG at specified times. The supply of natural gas to our Liquefaction Projects to meet our LNG production requirements timely and at sufficient quantities is critical to our operations and the fulfillment of our customer contracts. However, we may not be able to purchase or receive physical delivery of natural gas as a result of various factors, including non-delivery or untimely delivery by our suppliers, depletion of natural gas reserves within regional basins and disruptions to pipeline operations as described in the risk factor *Disruptions to the third party supply of natural gas to our pipelines and facilities could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.* Our risk is in part mitigated by the diversification of our natural gas supply and transportation across suppliers and pipelines, and regionally across basins, and additionally, we have provisions within our supplier contracts that provide certain protections against non-performance. Further, provisions within our SPAs provide certain protection against force majeure events. While historically we have not incurred significant or prolonged disruptions to our natural gas supply that have resulted in a material adverse impact to our operations, due to the criticality of natural gas supply to our production of LNG, our failure to purchase or receive physical delivery of sufficient quantities of natural gas under circumstances where we may not be protected could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our ability to complete development and/or construction of additional Trains, including the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, will be contingent on our ability to obtain additional funding. If we are unable to obtain sufficient funding, we may be unable to fully execute our business strategy.

We continuously pursue liquefaction expansion opportunities and other projects along the LNG value chain. As described further in Items 1. and 2. Business and Properties, we are currently developing the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project. The commercial development of an LNG facility takes a number of years and requires a substantial capital investment that is dependent on sufficient funding and commercial interest, among other factors.

We will require significant additional funding to be able to commence construction of the CCL Midscale Trains 8 & 9 Project, the SPL Expansion Project and any additional expansion projects, which we may not be able to obtain at a cost that results in positive economics, or at all. The inability to achieve acceptable funding may cause a delay in the development or construction of the CCL Midscale Trains 8 & 9 Project, the SPL Expansion Project or any additional expansion projects, and we may not be able to complete our business plan, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Cost overruns and delays in the completion of our expansion projects, including the Corpus Christi Stage 3 Project, the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, as well as difficulties in obtaining sufficient financing to pay for such costs and delays, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our investment decision on the Corpus Christi Stage 3 Project and any potential future expansion of LNG facilities, including the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, relies on cost estimates developed initially through front end engineering and design studies. However, due to the size and duration of construction of an LNG facility, the actual construction costs may be significantly higher than our current estimates as a result of many factors, including but not limited to changes in scope, the ability of Bechtel Energy Inc. (**"Bechtel"**) and our other contractors to execute successfully under their agreements, changes in commodity prices (particularly nickel and steel), escalating labor costs and the potential need for additional funds to be expended to maintain construction schedules or comply with existing or future environmental or other regulations. As construction progresses, we may decide or be forced to submit change orders to our contractor that could result in longer construction periods, higher construction costs or both, including change orders to comply with existing or future environmental or other regulations. Additionally, our SPAs generally provide that the customer may terminate that SPA if the relevant Train does not timely commence commercial operations. As a result, any significant construction delay, whatever the cause, could have a material adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Significant increases in the cost of a liquefaction project beyond the amounts that we estimate could impact the commercial viability of the project as well as require us to obtain additional sources of financing to fund our operations until the applicable liquefaction project is fully constructed (which could cause further delays), thereby negatively impacting our business and limiting our growth prospects. While historically we have not experienced cost overruns or construction delays that have had a significant adverse impact on our operations, factors giving rise to such events in the future may be outside of our control and could have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We are subject to significant construction and operating hazards and uninsured risks, one or more of which may create significant liabilities and losses for us.

The construction and operation of our LNG terminals and our pipelines are, and will be, subject to the inherent risks associated with these types of operations as discussed throughout our risk factors, including explosions, breakdowns or failures of equipment, operational errors by vessel or tug operators, pollution, release of toxic substances, fires, hurricanes and adverse weather conditions and other hazards, each of which could result in significant delays in commencement or interruptions of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations and the facilities and vessels of third parties on which our operations are dependent face possible risks associated with acts of aggression or terrorism.

We do not, nor do we intend to, maintain insurance against all of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. Although losses incurred as a result of self insured risk have not been material historically, the occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We are dependent on our EPC partners and other contractors for the successful completion of the Corpus Christi Stage 3 Project and any potential expansion projects, including the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project.

Timely and cost-effective completion of the Corpus Christi Stage 3 Project and any potential expansion projects, including the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, in compliance with agreed specifications is central to our business strategy and is highly dependent on the performance of our EPC partners, including Bechtel, and our other contractors under their agreements. The ability of our EPC partners and our other contractors to perform successfully under their agreements is dependent on a number of factors, including their ability to:

- design and engineer each Train to operate in accordance with specifications;
- engage and retain third party subcontractors and procure equipment and supplies;
- respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control;
- attract, develop and retain skilled personnel, including engineers;
- post required construction bonds and comply with the terms thereof;
- manage the construction process generally, including coordinating with other contractors and regulatory agencies; and
- maintain their own financial condition, including adequate working capital.

Although some agreements may provide for liquidated damages if the contractor fails to perform in the manner required with respect to certain of its obligations, the events that trigger a requirement to pay liquidated damages may delay or impair the operation of the Corpus Christi Stage 3 Project and any potential expansion projects, including the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, and any liquidated damages that we receive may not be sufficient to cover the damages that we suffer as a result of any such delay or impairment. The obligations of EPC partners and our other contractors to pay liquidated damages under their agreements are subject to caps on liability, as set forth therein.

Furthermore, we may have disagreements with our contractors about different elements of the construction process, which could lead to the assertion of rights and remedies under their contracts and increase the cost of the Corpus Christi Stage 3 Project and any potential expansion projects, including the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, or result in a contractor's unwillingness to perform further work. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor. This would likely result in significant project delays and increased costs, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

There may be impediments to the transport of LNG, such as shortages of LNG vessels worldwide or operational impacts on LNG shipping, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We sell a significant amount of our LNG under delivered at terminal (**"DAT"**) terms requiring delivery to international destinations. To fulfill our transportation requirements under these arrangements, including those under long term SPAs, we depend on the ability to secure chartered vessels often through long term lease arrangements. The construction and delivery of LNG vessels require significant capital and long construction lead times, and we may execute charters several years before the lease arrangements commence.

Although we actively manage our vessel requirements in response to the market and our customer contracts, the availability of LNG vessels and transportation costs could be impacted to the detriment of our business and our customers because of:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- shortages of or delays in the receipt of necessary construction materials;
- political or economic disturbances;
- acts of war or piracy;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances;
- bankruptcy or other financial crisis of shipbuilders or shipowners;
- quality or engineering problems;
- disruptions to maritime transportation routes, such as the recent security situation in the Gulf of Aden and congestion at the Panama Canal resulting from decreased water levels caused by prolonged drought conditions; and
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire.

While our chartered vessels are operated by the ship owners and we are exposed to risks outside of our own control, we are generally protected through provisions in our charter agreements from transportation disruptions on the part of the ship owner, including disruptions due to off-hire and downtime periods or shipping delays. However, other events outside of our control where we may not be protected may have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Additionally, while our vessel charters allow us to secure fixed rates under long term contracts (in certain cases subject to inflation) and we generally structure our SPAs to recover any increase in such costs, our profitability, particularly relating to our short term or spot LNG sales outside of our SPAs, is largely dependent on the strength of international LNG markets. While historical downturns have not had a material adverse impact to our operations or results, any prolonged weakening of such markets could result in depressed or negative margins. See the risk factor *Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect our LNG business and the performance of our customers and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects* for additional discussion.

Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect our LNG business and the performance of our customers and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our LNG business and the development of domestic LNG facilities and projects generally is based on assumptions about the future availability and price of natural gas and LNG and the prospects for international natural gas and LNG markets. Natural gas and LNG prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to one or more of the following factors:

- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient LNG tanker capacity;
- weather conditions, including temperature volatility resulting from climate change, and extreme weather events may lead to unexpected distortion in the balance of international LNG supply and demand;
- reduced demand and lower prices for natural gas;
- 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, including as a result of any potential ban on production of natural gas through hydraulic fracturing;

- cost improvements that allow competitors to provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported LNG, natural gas or alternative energy sources, which may reduce the demand for imported LNG and/or natural gas;
- political conditions in customer regions;
- sudden decreases in demand for LNG as a result of natural disasters or public health crises, including the occurrence of a pandemic, and other catastrophic events;
- adverse relative demand for LNG compared to other markets, which may decrease LNG imports from North America; 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 our LNG business and the performance of our customers, and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Failure of exported LNG to be a long term 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 Liquefaction Projects are dependent upon the ability of our SPA customers to deliver LNG supplies from the United States, 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 the United States 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 United States, which could increase the available supply of natural gas outside the United States and could result in natural gas in those markets being available at a lower cost than LNG exported to those markets.

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

As described in Market Factors and Competition, it is expected that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to alternative fossil fuel energy sources such as oil and coal. However, as a result of transitions globally from fossil-based systems of energy production and consumption to renewable energy sources, LNG may face increased competition from alternative, cleaner sources of energy as such alternative sources emerge. Additionally, LNG from the Liquefaction Projects also competes with other sources of LNG, including LNG that is priced to indices other than Henry Hub. Some of these sources of energy may be available at a lower cost than LNG from the Liquefaction Projects in certain markets. The cost of LNG supplies from the United States, including the Liquefaction Projects, may also be impacted by an increase in natural gas prices in the United States.

As described in Market Factors and Competition, we have contracted through our SPAs and IPM agreements approximately 95% of the total anticipated production from the Liquefaction Projects through the mid-2030s, excluding volumes from contracts with terms less than 10 years and volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation. However, as a result of the factors described above and other factors, the LNG we produce may not remain a long term competitive source of energy internationally, particularly when our existing long term contracts begin to expire. Any significant impediment to the ability to continue to secure long term commercial contracts or deliver LNG from the United States could have a material adverse effect on our customers and on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We face competition based upon the international market price for LNG.

Our Liquefaction Projects are subject to the risk of LNG price competition at times when we need to replace any existing SPA, whether due to natural expiration, default or otherwise, or enter into new SPAs. Factors relating to competition may prevent us from entering into a new or replacement SPA on economically comparable terms as existing SPAs, or at all. Such an event could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. 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 Projects;
- decreases in the cost of competing sources of natural gas or alternate fuels such as coal, heavy fuel oil and diesel;
- 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; and
- displacement of LNG by pipeline natural gas or alternate fuels in locations where access to these energy sources is not currently available.

A cyber attack involving our business, operational control systems or related infrastructure, or that of third party pipelines which supply the Liquefaction Facilities, could negatively impact our operations, result in data security breaches, impede the processing of transactions or delay financial or compliance reporting. These impacts could materially and adversely affect our business, contracts, financial condition, operating results, cash flow and liquidity.

The pipeline and LNG industries are increasingly dependent on business and operational control technologies to conduct daily operations. We rely on control systems, technologies and networks to run our business and to control and manage our trading, marketing, pipeline, liquefaction and shipping operations. Cyber attacks on businesses have escalated in recent years, including as a result of geopolitical tensions, and use of the internet, cloud services, mobile communication systems and other public networks exposes our business and that of other third parties with whom we do business to potential cyber attacks, including third party pipelines which supply natural gas to our Liquefaction Facilities. For example, in 2021 Colonial Pipeline suffered a ransomware attack that led to the complete shutdown of its pipeline system for six days. Should a multiple of the third party pipelines which supply our Liquefaction Facilities suffer similar concurrent attacks, the Liquefaction Facilities may not be able to obtain sufficient natural gas to operate at full capacity, or at all. A cyber attack involving our business or operational control systems or related infrastructure, or that of third party pipelines with which we do business, could negatively impact our operations, result in data security breaches, impede the processing of transactions, or delay financial or compliance reporting. These impacts could materially and adversely affect our business, contracts, financial condition, operating results, cash flow and liquidity.

We may experience increased labor costs, and the unavailability of skilled workers or our failure to attract and retain qualified personnel could adversely affect us. In addition, changes in our senior management or other key personnel could affect our business results.

We are dependent upon the available labor pool of skilled employees. We 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 pipelines and to provide our customers with the highest quality service. We are also subject to the Fair Labor Standards Act, which governs such matters as minimum wage, overtime and other working conditions. A shortage in the labor pool of skilled workers, remoteness of our site locations, general inflationary pressures, changes in applicable laws and regulations or labor disputes 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, thereby increasing our operating costs. In addition, we are also subject to increased competition for skilled workers from new entrants to the LNG market. Any increase in our operating costs could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We depend on our executive officers for various activities. We do not maintain key person life insurance policies on any of our personnel. Although we have arrangements relating to compensation and benefits with certain of our executive officers, we do not have any employment contracts or other agreements with key personnel binding them to provide services for any particular term, other than our employment agreement with our President and Chief Executive Officer. The loss of the services of any of these individuals could have a material adverse effect on our business.

Outbreaks of infectious diseases, such as COVID-19, at one or more of our facilities could adversely affect our operations.

Our facilities at the Sabine Pass LNG Terminal and Corpus Christi LNG Terminal are critical infrastructure and continued to operate during the COVID-19 pandemic through our implementation of workplace controls and pandemic risk reduction measures. While the COVID-19 pandemic, including subsequent variants, had no adverse impact on our on-going operations, the risk of future variants and other infectious diseases is unknown. While we believe we can continue to mitigate any significant adverse impact to our employees and operations at our critical facilities related to the virus in its current form, the outbreak of a more potent variant or another infectious disease in the future at one or more of our facilities could adversely affect our operations.

Risks Relating to Regulations

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the design, construction and operation of our facilities, the development and operation of our pipelines and the export of LNG could impede operations and construction and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The design, construction and operation of interstate natural gas pipelines, LNG terminals, including the Liquefaction Projects, the CCL Midscale Trains 8 & 9 Project, the SPL Expansion Project and other facilities, as well as the import and export of LNG and the purchase and transportation of natural gas, are highly regulated activities. Approvals of the FERC and DOE under Section 3 and Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, including several under the CAA and the CWA, are required in order to construct and operate an LNG facility and an interstate natural gas pipeline and export LNG.

To date, the FERC has issued orders under Section 3 of the NGA authorizing the siting, construction and operation of the six Trains and related facilities of the SPL Project, the three Trains and related facilities of the CCL Project and the seven midscale Trains and related facilities for the Corpus Christi Stage 3 Project, as well as orders under Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline and the Corpus Christi Pipeline. In May 2023, certain subsidiaries of CQP entered the pre-filing review process with the FERC under the NEPA for the SPL Expansion Project and in March 2023, certain of our subsidiaries submitted an application with the FERC under the NGA for the CCL Midscale Trains 8 & 9 Project. To date, the DOE has also issued orders under Section 4 of the NGA authorizing SPL, CCL and the Corpus Christi Stage 3 Project to export domestically produced LNG. In January 2024, the Biden Administration announced a temporary pause on pending decisions on exports of LNG to non-FTA countries until the DOE can update the underlying analyses for authorizations. We do not believe such a pause will have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, or liquidity. The CCL Midscale Trains 8 & 9 Project is currently our only project pending non-FTA export approval with the DOE, although such approval is first subject to the receipt of regulatory permit approval from the FERC, responsive to our formal application in March 2023. We would anticipate seeking non-FTA export authorization from the DOE on the SPL Expansion Project in the future, having entered the pre-filing review process with the FERC in May 2023. Additionally, we hold certificates under Section 7(c) of the NGA that grant us land use rights relating to the situation of our pipelines on land owned by third parties. If we were to lose these rights or be required to relocate our pipelines, our business could be materially and adversely affected.

Authorizations obtained from the FERC, DOE and other federal and state regulatory agencies contain ongoing conditions that we must comply with. Failure to comply with or our inability to obtain and maintain existing or newly imposed approvals, permits and filings that may arise due to factors outside of our control such as a U.S. government disruption or shutdown, political opposition or local community resistance to our operations could impede the operation and construction of our infrastructure. In addition, certain of these governmental permits, approvals and authorizations are or may be subject to rehearing requests, appeals and other challenges. There is no assurance that we will obtain and maintain these governmental permits, approvals and authorizations, or that we will be able to obtain them on a timely basis. Any impediment could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our interstate natural gas pipelines and their FERC gas tariffs are subject to FERC regulation. If we fail to comply with such regulation, we could be subject to substantial penalties and fines.

Our interstate natural gas pipelines are subject to regulation by the FERC under the NGA and the Natural Gas Policy Act of 1978 (the **"NGPA"**). The FERC regulates the purchase and transportation of natural gas in interstate commerce, including the construction and operation of pipelines, the rates, terms and conditions of service and abandonment of facilities. Under the NGA, the rates charged by our interstate natural gas pipelines must be just and reasonable, and we are prohibited from unduly preferring or unreasonably discriminating against any potential shipper with respect to pipeline rates or terms and conditions of service. If we fail to comply with all applicable statutes, rules, regulations and orders, our interstate pipelines could be subject to substantial penalties and fines.

In addition, as a natural gas market participant, should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct, the FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1.5 million per day for each violation.

Although the FERC has not imposed fines or penalties on us to date, we are exposed to substantial penalties and fines if we fail to comply with such regulations.

Existing and future safety, environmental and similar laws and governmental regulations could result in increased compliance costs or additional operating costs or construction costs and restrictions.

Our business is and will be subject to extensive federal, state and local laws, rules and regulations applicable to our construction and operation activities relating to, among other things, air quality, water quality, waste management, natural resources and health and safety. Many of these laws and regulations, such as the CAA, the Oil Pollution Act, the CWA and the RCRA, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our facilities, and require us to maintain permits and provide governmental authorities with access to our facilities for inspection and reports related to our compliance. In addition, certain laws and regulations authorize regulators having jurisdiction over the construction and operation of our LNG terminals, docks and pipelines, including FERC, PHMSA, EPA and the United States Coast Guard, to issue regulatory enforcement actions, which may restrict or limit operations or increase compliance or operating costs. Violation of these laws and regulations could lead to substantial liabilities, compliance orders, fines and penalties, difficulty obtaining and maintaining permits from regulatory agencies or increased capital expenditures that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. 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. As the owner and operator of our facilities, we could be liable for the costs of cleaning up hazardous substances released into the environment at or from our facilities and for resulting damage to natural resources.

The EPA has finalized or proposed multiple GHG regulations that impact our assets and supply chain. On December 2, 2023, the EPA issued final rules to reduce methane and VOC emissions from new, existing and modified emission sources in the oil and gas sector. These regulations will require monitoring of methane and VOC emissions at our compressor stations. Further, the IRA includes a charge on methane emissions above certain emissions thresholds employing empirical emissions data that will apply to our facilities beginning in calendar year 2024. In January 2024, the EPA issued a proposed rule to impose and collect methane emissions charges authorized under the IRA. In addition, other international, federal and state initiatives may be considered in the future to address GHG emissions through treaty commitments, direct regulation, market-based regulations such as a GHG emissions tax or cap-and-trade programs or clean energy or performance-based standards. Such initiatives could affect the demand for or cost of natural gas, which we consume at our terminals, or could increase compliance costs for our operations.

Revised, reinterpreted or additional guidance, laws and regulations at local, state, federal or international levels that result in increased compliance costs or additional operating or construction costs and restrictions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. It is not possible at this time to predict how future regulations or legislation may address GHG emissions and impact our business.

On February 28, 2022, the EPA removed a stay of formaldehyde standards in the NESHAP Subpart YYYY for stationary combustion turbines located at major sources of HAP emissions. Owners and operators of lean remix gas-fired turbines and diffusion flame gas-fired turbines at major sources of HAP that were installed after January 14, 2003 were required to comply with NESHAP Subpart YYYY by March 9, 2022 and demonstrate initial compliance with those requirements by September 5, 2022. We do not believe that our operations, or the construction and operations of our liquefaction facilities, will be materially and adversely affected by such regulatory actions.

Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to or exported from our terminals or climate policies of destination countries in relation to their obligations under the Paris Agreement or other national or international climate change-related policies, could cause additional expenditures, restrictions and delays in our business and to our proposed construction activities, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances.

Total expenditures related to environmental and similar laws and governmental regulations, including capital expenditures, were immaterial to our Consolidated Financial Statements for the years ended December 31, 2023, 2022 and 2021. Revised, reinterpreted or additional laws and regulations that result in increased compliance, operating or construction costs or restrictions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Pipeline safety and compliance programs and repairs may impose significant costs and liabilities on us.

The PHMSA requires pipeline operators to develop management programs to safely operate and maintain their pipelines and to comprehensively evaluate certain areas along their pipelines and take additional measures where necessary to protect pipeline segments located in "high or moderate consequence areas" where a leak or rupture could potentially do the most harm. As an operator, we are required to:

- perform ongoing assessments of pipeline safety and compliance;
- 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 preventative and mitigating actions.

We are required to utilize pipeline integrity management programs that are intended to maintain pipeline integrity. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should we fail to comply with applicable statutes and the Office of Pipeline Safety's rules and related regulations and orders, we could be subject to significant penalties and fines, which for certain violations can aggregate up to as high as $2.7 million.

Additions or changes in tax laws and regulations could potentially affect our financial results or liquidity.

We are subject to various types of tax arising from normal business operations in the jurisdictions in which we operate and transact. Any changes to local, domestic or international tax laws and regulations, or their interpretation and application, including the Organization for Economic Cooperation and Development's (the **"OECD"**) adopted model rules for a 15% global minimum tax (commonly referred to as Pillar Two), could affect our tax obligations, profitability and cash flows in the future. In addition, tax rates in the various jurisdictions in which we operate may change significantly due to political or economic factors beyond our control. We continuously monitor and assess proposed tax legislation that could negatively impact our business.

The IRA imposes a 15% CAMT effective in 2023, on an applicable corporation with average AFSI in excess of $1 billion for any three consecutive years preceding the current year. Cheniere expects to be an applicable corporation beginning in 2024. Based on the CAMT rules as currently enacted, the CAMT tax base would include any gains or losses arising from changes in fair value of our commodity derivatives that are recorded to our Consolidated Statements of Operations. Volatility in underlying commodity and financial markets could accelerate and cause volatility in our future cash tax payments, particularly in periods of significant commodity, currency or financial market variability. If the CAMT applies, we could be subject to an additional tax liability beyond the regular federal corporate tax liability, despite our federal net operating loss carryforwards, which could adversely impact our liquidity. Additionally, any implementing regulatory guidance related to the

CAMT issued by the U.S. Department of Treasury and the Internal Revenue Service in the future could potentially affect both the timing and amount of our CAMT cash tax payments.

Our ability to utilize our net operating loss carryforwards and certain other tax attributes may be limited.

As of December 31, 2023, our federal net operating loss (**"NOL"**) carryforwards were approximately $4.3 billion and not subject to expiration. We may experience an ownership change as a result of future changes in our stock ownership (some of which changes may not be within our control). If Cheniere undergoes an ownership change (generally defined as a greater than 50% cumulative change in the equity ownership of certain shareholders over a rolling three-year period) under Section 382 of the Internal Revenue Code, our ability to use our pre-ownership change NOL carryforwards to offset future taxable income may be limited. This, in turn, could materially delay our ability to use our NOLs to offset future taxable income and have an adverse effect on our future cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cyberattacks represent a potentially significant risk to the Company and our industry. We have implemented policies and procedures that are intended to manage and reduce this risk.

Risk Management and Strategy

As part of our broader approach to risk management, our cybersecurity program is designed to follow an "identify, protect, detect, respond and recover" approach to cybersecurity that is based off of the National Institute of Standards and Technology Cybersecurity Framework (**"CSF"**). Our strategy also includes segmentation of corporate and operations networks, defense in depth and the least privileged access principle. Operational networks have fundamentally distinct safety and reliability standards and pose unique threats in comparison to information technology networks. Realizing these differences, we routinely evaluate opportunities to refine our cybersecurity program in order to mitigate operational network risks. We include business continuity planning as a component of our strategy to help ensure critical systems are available to support our company in the instance of a disruptive event. We also participate in various industry organizations to stay abreast of recent trends and developments.

On an ongoing basis, we assess our people, processes and technology and, when necessary, adjust the overall program in an effort to adapt to the ever-evolving cyber and geopolitical landscapes. We conduct regular assessments and audits, cross-functional risk mitigation exercises and risk strategy sessions to identify cybersecurity risks, applicable regulatory requirements and industry standards. These engagements are also designed to exercise, assess the maturity of and enhance our Cyber Incident Response Plan. To support these efforts, we have contracted with third parties to perform facility and system penetration tests, compromise assessments of information technology systems, and security maturity assessments of our corporate and operational networks. We maintain a training program to help our personnel identify and assist in mitigating cybersecurity and data security risks. Our employees and Board members participate in annual training, user awareness campaigns and additional issue-specific training as needed. We also provide annual training for certain contractors who have access to our information technology networks.

With respect to third party service providers, our information security program includes conducting risk-based due diligence of certain service providers' information security programs prior to onboarding. We seek to contractually require third party service providers with access to our information technology systems, sensitive business data or personal information to maintain reasonable security controls and restrict their ability to use our data, including personal information, for purposes other than to provide services to us, except as required by applicable law. We also seek to negotiate contractual requirements which compel our service providers to notify us of information security incidents occurring on their systems which may affect our systems or data, including personal information.

During the year ended December 31, 2023, cybersecurity incidents and threats did not materially affect our business, results of operations or financial condition.

Governance

Our cybersecurity leadership team consists of our Director and Chief Information Security Officer (our **"CISO"**), Vice President and Chief Information Officer and Senior Vice President of Shared Services. These individuals collectively provide the strategic oversight of our cybersecurity governance, cyber risk management and security operations and are responsible for maintaining our technology defense posture and program. They have decades of experience managing strategic technology operations, including the identification of cybersecurity risk and the defense of information technology assets from global threats. Our CISO's experience includes assessing risks, implementing governance programs, and responding to threats in oil and gas, electric and natural gas utilities and nuclear power generation companies. He maintains a Certified Information Security Manager certification from ISACA, secret clearance from the Department of Homeland Security and has played an active role in the development of various cybersecurity standards including the CSF.

Risks that could affect us are an integral part of our Board and Audit Committee deliberations throughout the year. Cybersecurity risks are integrated into our enterprise risk assessment process, which is reviewed by our Board at least annually. Our Board has oversight responsibility for assessing the primary risks facing us (including cybersecurity risks), the relative magnitude of these risks and management's plan for mitigating these risks, while the Audit Committee has been delegated the authority to oversee and periodically review the security of our information technology systems and controls, including programs and defenses against cybersecurity threats. The Audit Committee discusses with management our cybersecurity risk exposures and the steps management has taken to mitigate such exposures, including our risk assessment and risk management policies. On a quarterly basis, our cybersecurity leadership team updates the Audit Committee on the overall status of our cybersecurity program, key operational metrics, current assessments, cybersecurity issues or events and pertinent events related to cybersecurity.

For additional information about cybersecurity risks, see the risk *A cyber attack involving our business, operational control systems or related infrastructure, or that of third party pipelines which supply the Liquefaction Facilities, could negatively impact our operations, result in data security breaches, impede the processing of transactions or delay financial or compliance reporting* under Risks Relating to Our Operations and Industry in Item 1A.Risk Factors.

ITEM 3. LEGAL PROCEEDINGS

We may in the future be involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters.

LDEQ Matter

Certain of our subsidiaries are in discussions with the LDEQ to resolve alleged non-compliance with national emission standards for formaldehyde from combustion turbines at the Sabine Pass LNG Terminal. The allegations are identified in a Consolidated Compliance Order and Notice of Potential Penalty, Tracking No. AE-CN-22-00833 (the **"2023 Compliance Order"**) issued by the LDEQ on April 12, 2023. In August 2004, the EPA stayed the application of the emission standard to combustion turbines such as those at the Sabine Pass LNG Terminal. In March 2022, the EPA lifted the stay, and in June 2022 our subsidiaries petitioned the EPA and LDEQ for approval of additional operating parameters to demonstrate compliance with the emission limitation. The petition remains pending. Our subsidiaries continue to work with the LDEQ to resolve the matters identified in the 2023 Compliance Order, including the petition pending with the EPA. As of December 2023, our subsidiaries have filed test results with the LDEQ indicating that for the initial compliance period all 44 turbines meet the relevant compliance standard. We do not expect that any ultimate penalty will have a material adverse impact on our financial results.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

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

Market Information, Holders and Dividend Policy

Our common stock has traded on the New York Stock Exchange under the symbol "LNG" since February 5, 2024, and previously traded on the NYSE American or its predecessors under the symbol "LNG" from March 24, 2003 through February 3, 2024. As of February 16, 2024, we had approximately 234.7 million shares of common stock outstanding held by 75 record owners.

We intend to continue to declare and pay quarterly dividends, with the goal of increasing the dividend over time. The declaration of dividends is subject to the discretion of our Board, and will depend on our financial condition and other factors deemed relevant by the Board. See the risk *Our ability to declare and pay dividends and repurchase shares is subject to certain considerations* under Risks Relating to Our Financial Matters in Item 1A. Risk Factors.

Purchase of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes stock repurchases for the three months ended December 31, 2023:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as a Part of Publicly Announced Plans	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans (in millions) (1)
October 1 - 31, 2023	732,055	$167.95	732,055	$2,357
November 1 - 30, 2023	634,274	$174.28	634,274	$2,247
December 1 - 31, 2023	607,966	$173.21	607,966	$2,141
Total	1,974,295	$171.60	1,974,295	

(1) See Note 19—Share Repurchase Programs of our Notes to Consolidated Financial Statements for details on the amount authorized by our Board under our share repurchase programs.

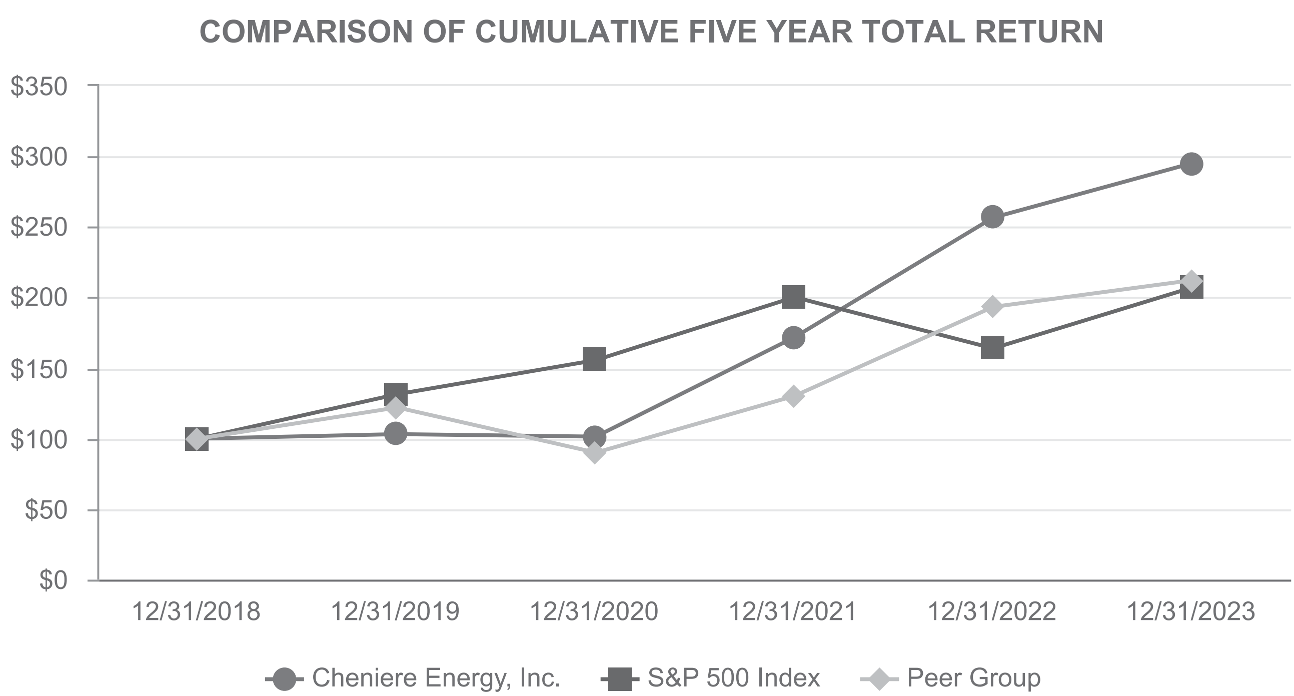
Total Stockholder Return

The following is a customized peer group consisting of 17 companies (the **"Peer Group"**) that were selected because they are publicly traded companies that have comparable Global Industry Classification Standards. We also took into consideration those companies that have similar market capitalization, enterprise values and operating characteristics and capital intensity.

Peer Group	
Air Products and Chemicals, Inc. (APD)	Marathon Petroleum Corporation (MPC)
Baker Hughes Company (BKR)	Occidental Petroleum Corporation (OXY)
ConocoPhillips (COP)	ONEOK, Inc. (OKE)
Enterprise Products Partners L.P. (EPD)	Phillips 66 (PSX)
EOG Resources, Inc. (EOG)	Suncor Energy Inc. (SU)
Halliburton Company (HAL)	Targa Resources Corp. (TRGP)
Hess Corporation (HES)	Valero Energy Corporation (VLO)
Kinder Morgan, Inc. (KMI)	The Williams Companies, Inc. (WMB)
LyondellBasell Industries N.V. (LYB)	

The following graph compares the five-year total return on our common stock, the S&P 500 Index and our Peer Group. The graph was constructed on the assumption that $100 was invested in our common stock, the S&P 500 Index and our Peer Group on December 31, 2018 and that any dividends were fully reinvested.

	December 31,					
Company / Index	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Cheniere Energy, Inc.	$ 100.00	$ 103.18	101.42	$ 171.88	$ 256.67	$ 295.20
S&P 500 Index	100.00	131.48	155.65	200.29	163.98	207.04
Peer Group	100.00	122.09	90.09	130.28	193.39	212.27



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 performance, current financial condition and outlook for the future. Discussion of 2021 items and variance drivers between the year ended December 31, 2022 as compared to December 31, 2021 are not included herein and can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our annual report on Form 10-K for the fiscal year ended December 31, 2022.

Our discussion and analysis includes the following subjects:

- Overview
- Overview of Significant Events
- Market Environment
- Results of Operations
- Liquidity and Capital Resources
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

Overview

We are an energy infrastructure company primarily engaged in LNG-related businesses. We provide clean, secure and affordable LNG to integrated energy companies, utilities and energy trading companies around the world. We operate two natural gas liquefaction and export facilities at Sabine Pass, Louisiana and near Corpus Christi, Texas. For further discussion of our business, see Items 1. and 2. Business and Properties.

Our long-term customer arrangements form the foundation of our business and provide us with significant, stable, long-term cash flows. Through our SPAs and IPM agreements, we have contracted approximately 95% of the total anticipated production from the Liquefaction Projects through the mid-2030s with approximately 16 years of weighted average remaining life as of December 31, 2023, excluding volumes from contracts with terms less than 10 years and volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation. The majority of our contracts are fixed-priced, long-term SPAs consisting of a fixed fee per MMBtu of LNG plus a variable fee per MMBtu of LNG, with the variable fees generally structured to cover the cost of natural gas purchases, transportation and liquefaction fuel consumed to produce LNG. Since we procure most of our feedstock for LNG production from the U.S., the structure of these contracts helps limit our exposure to fluctuations in U.S. natural gas prices. During 2023, we continued to grow our portfolio of SPA and IPM agreements, and we believe that continued global demand for natural gas and LNG, as further described in Market Factors and Competition in Items 1. and 2. Business and Properties, will provide a foundation for additional growth in our portfolio of customer contracts in the future. The continued strength and stability of our long-term cash flows served as the foundation of our revised comprehensive, long-term capital allocation plan announced in 2022, which includes an increased share repurchase authorization, decreased consolidated long-term leverage target, increased dividends and continued investment in accretive organic growth.

Overview of Significant Events

Our significant events since January 1, 2023 and through the filing date of this Form 10-K include the following:

Strategic

- In November 2023, we announced that SPL Stage V entered into an IPM agreement with ARC Resources U.S. Corp., a subsidiary of ARC Resources Ltd., to purchase 140,000 MMBtu per day of natural gas at a price based on the Dutch Title Transfer Facility (**"TTF"**), less a fixed regasification fee, fixed LNG shipping costs and a fixed liquefaction fee, for a term of approximately 15 years commencing with commercial operations of the first train of the SPL Expansion Project. This agreement is subject to CQP making a positive FID on the first train of the SPL Expansion Project or CQP unilaterally waiving that requirement.
- Cheniere Marketing entered into long-term SPAs with Foran Energy Group Co. Ltd., BASF, ENN LNG (Singapore) Pte. Ltd., Equinor ASA and Korea Southern Power Co. Ltd. with estimated volumes totaling approximately 106 million tonnes of LNG and expected deliveries between 2026 and 2050. Approximately 65 million tonnes is subject to CQP making a positive FID on the first or second trains of the SPL Expansion Project, as applicable, or us unilaterally waiving that requirement. Each of these SPAs permit Cheniere Marketing to assign or novate the agreement to certain affiliates at a later date.
- In May 2023, certain subsidiaries of CQP entered the pre-filing review process with the FERC under the NEPA for the SPL Expansion Project, and in April 2023, one of our subsidiaries executed a contract with Bechtel to provide the front end engineering and design work on the project.
- In April 2023, certain of our subsidiaries filed an application with the DOE with respect to the CCL Midscale Trains 8 & 9 Project, requesting authorization to export LNG to FTA countries and non-FTA countries. In July 2023, we received authorization from the DOE to export LNG to FTA countries.
- In March 2023, certain of our subsidiaries submitted an application with the FERC under the NGA for the CCL Midscale Trains 8 & 9 Project.
- On January 2, 2023, Corey Grindal, formerly Executive Vice President, Worldwide Trading, was promoted to Executive Vice President and Chief Operating Officer of the Company.

Operational

- As of February 16, 2024, approximately 3,280 cumulative LNG cargoes totaling over 225 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Projects.

Financial

- We closed the following debt transactions:
    - In June 2023, CQP issued $1.4 billion aggregate principal amount of 5.950% Senior Notes due 2033 (the **"2033 CQP Senior Notes"**). Using contributed proceeds from the 2033 CQP Senior Notes together with cash on hand, SPL redeemed $1.4 billion of its 5.750% Senior Secured Notes due 2024 (the **"2024 SPL Senior Notes"**) in July 2023.
    - In June 2023, CQP entered into a $1.0 billion Senior Unsecured Revolving Credit and Guaranty Agreement (the **"CQP Revolving Credit Facility"**), and SPL entered into a $1.0 billion Senior Secured Revolving Credit and Guaranty Agreement (the **"SPL Revolving Credit Facility"**). The CQP Revolving Credit Facility and SPL Revolving Credit Facility each refinanced and replaced the respective existing credit facilities to, among other things, (1) extend the maturity date thereunder, (2) reduce the rate of interest and commitment fees applicable thereunder and (3) make certain other changes to the terms and conditions of the prior credit facilities.

- We received the following upgrades from credit rating agencies, including S&P Global Ratings (**“S&P”**), Moody’s Investor Service (**“Moody’s”**) and Fitch Ratings (**“Fitch”**), each with a stable outlook:

Date	Entity	Previous Rating	Upgraded Rating	Rating Agency
October 2023	CCH	BBB-	BBB	S&P
August 2023	Cheniere	Ba1	Baa3	Moody’s
August 2023	CCH	Baa3	Baa2	Moody’s
August 2023	SPL	BBB	BBB+	Fitch
July 2023	CCH	BBB-	BBB	Fitch
February 2023	SPL	BBB	BBB+	S&P
January 2023	Cheniere	—	BBB-	Fitch

- During the year ended December 31, 2023, we accomplished the following pursuant to our capital allocation priorities:
  - We prepaid $1.2 billion of consolidated long-term indebtedness, which excludes prepayments associated with debt refinancing and includes $600 million of debt repurchases in the open market.
  - We repurchased approximately 9.5 million shares of our common stock as part of our share repurchase program for $1.5 billion.
  - We paid dividends of $1.620 per share of common stock during the year ended December 31, 2023.
  - We continued to invest in accretive organic growth, including our investment in the Corpus Christi Stage 3 Project, as further described under *Investing Cash Flows* in Sources and Uses of Cash within Liquidity and Capital Resources.

Market Environment

In 2023, the LNG market continued to rebalance with robust LNG flows to Europe maintaining the region’s underground storage inventories at high levels, and weak demand in Japan and Korea largely offsetting a modest rebound in China and other emerging economies in Asia. Price levels started moving towards pre-Russia-Ukraine war levels in the second quarter of 2023 and have for the most part normalized versus pre-war levels, as concerns about physical market tightness dissipated. However, extensive upstream maintenance in Norway and concerns about tight supply capacity amid strike threats in Australia elevated prices during the third quarter of 2023 and brought some volatility back to the market, albeit not at much lower levels than those seen in 2022. These conditions were quickly resolved, and winter prices remained within a more normal level, despite the eruption of military conflict in the Middle East in October.

The TTF monthly settlement prices averaged $13.73/MMBtu in 2023, over 66% lower year-over-year and 4.6% lower than 2021. Similarly, the 2023 average settlement price for the Japan Korea Marker (**“JKM”**) decreased 53% year-over-year to an average of $16.13/MMBtu in 2023. Prices in the fourth quarter of 2023 also decreased, with TTF averaging $13.66/MMBtu and JKM $14.97/MMBtu - both significantly below levels seen in the previous two years. The Henry Hub benchmark also witnessed a similar year-over-year drop albeit from a much lower base. The Henry Hub average settlement price in 2023 was $2.74, down approximately 59% from $6.64/MMBtu in 2022 during the height of the energy crisis in Europe.

The U.S. played a significant role in balancing the global market in 2023, exporting approximately 86 million tonnes of LNG, a gain of approximately 13% from 2022, due in part to the return of Freeport LNG to operations. Exports from our Liquefaction Projects reached 44 million tonnes in aggregate, representing over 50% of total U.S. exports for the year, according to Kpler data.

Global LNG demand grew by approximately 3% from 2022, adding 10.5 million tonnes to the overall market. Although overall Asian demand has increased from 2022, weakness in Japan, mainly due to improved nuclear availability, along with continued gas demand destruction in Europe, especially in the residential sector, exerted downward pressure on the market and kept LNG and gas prices from increasing. Despite the decrease in Japanese demand, which was down approximately 8% or 6 mtpa year-over-year, Asia’s LNG imports increased roughly 4% year-over-year in 2023 to approximately 263 mtpa. This uptick was largely due to an approximately 8.4 mtpa year-over-year growth in South and Southeast Asia’s demand and a modest rebound in China’s economy, which resulted in approximately 12% or 7.5 mtpa increase in LNG imports into the country. In Europe, despite continued declines in gas demand, LNG imports were flat year-over-year as pipeline flows from Russia to the EU remained low at 27 billion cubic meters (**“Bcm”**), down 36 Bcm or 57% year-over-year.

The market dynamics brought on by the need to displace and replace Russian gas into Europe in 2023 resulted in a notable uptick in long-term LNG contracting and a push for LNG project FIDs. Commercial activity in 2023 continued to build on last year’s momentum with executed long-term SPAs in the U.S. reaching approximately 23 mtpa for the year, of which our SPAs and IPM agreements totaled approximately 6.5 mtpa. This contractual momentum over the past two years led to the positive FID of nearly 40 mtpa of U.S. LNG capacity in 2023, and we anticipate that a portion of these contracts will support our future growth.

Despite the global impacts of the Russia-Ukraine war, we do not believe we have significant exposure to adverse direct or indirect impacts of the war, as we do not conduct business in Russia and refrain from business dealings with Russian entities. Additionally, we are not aware of any specific adverse direct or indirect effects of the Russia-Ukraine war or the Israel-Hamas war on our supply chain. Consequently, we believe we are well positioned to help meet the increased demand of our international LNG customers to overcome their supply shortages.

Results of Operations

Consolidated results of operations

	Year Ended December 31,		
(in millions, except per share data)	2023	2022	Variance
Revenues			
LNG revenues	$ 19,569	$ 31,804	$ (12,235)
Regasification revenues	135	1,068	(933)
Other revenues	690	556	134
Total revenues	20,394	33,428	(13,034)
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	1,356	25,632	(24,276)
Operating and maintenance expense	1,835	1,681	154
Selling, general and administrative expense	474	416	58
Depreciation and amortization expense	1,196	1,119	77
Other	44	21	23
Total operating costs and expenses	4,905	28,869	(23,964)
Income from operations	15,489	4,559	10,930
Other income (expense)			
Interest expense, net of capitalized interest	(1,141)	(1,406)	265
Gain (loss) on modification or extinguishment of debt	15	(66)	81
Interest and dividend income	211	57	154
Other income (expense), net	4	(50)	54
Total other expense	(911)	(1,465)	554
Income before income taxes and non-controlling interest	14,578	3,094	11,484
Less: income tax provision	2,519	459	2,060
Net income	12,059	2,635	9,424
Less: net income attributable to non-controlling interest	2,178	1,207	971
Net income attributable to common stockholders	$ 9,881	$ 1,428	$ 8,453
Net income per share attributable to common stockholders—basic	$ 40.99	$ 5.69	$ 35.30
Net income per share attributable to common stockholders—diluted	$ 40.72	$ 5.64	$ 35.08

Volumes loaded and recognized from the Liquefaction Projects

(in TBtu)	Year Ended December 31, 2023	2022	Variance
Volumes loaded during the current period	2,299	2,295	4
Volumes loaded during the prior period but recognized during the current period	56	49	7
Less: volumes loaded during the current period and in transit at the end of the period	(37)	(56)	19
Total volumes recognized in the current period	2,318	2,288	30

Components of LNG revenues and corresponding LNG volumes delivered

	Year Ended December 31, 2023	2022	Variance
LNG revenues *(in millions)*:			
LNG from the Liquefaction Projects sold under third party long-term agreements (1)	$ 12,820	$ 20,702	$ (7,882)
LNG from the Liquefaction Projects sold by our integrated marketing function under short-term agreements	6,028	10,169	(4,141)
LNG procured from third parties	359	760	(401)
Net derivative gains (losses)	110	(328)	438
Other revenues	252	501	(249)
Total LNG revenues	$ 19,569	$ 31,804	$ (12,235)
Volumes delivered as LNG revenues *(in TBtu)*:			
LNG from the Liquefaction Projects sold under third party long-term agreements (1)	2,034	1,926	108
LNG from the Liquefaction Projects sold by our integrated marketing function under short-term agreements	284	362	(78)
LNG procured from third parties	35	29	6
Total volumes delivered as LNG revenues	2,353	2,317	36

(1) Long-term agreements include agreements with an initial tenor of 12 months or more.

Net income attributable to common stockholders

The favorable variance of $8.5 billion for the year ended December 31, 2023 as compared to the same period of 2022 was primarily attributable to a favorable variance of $14.4 billion (before tax and the impact of non-controlling interest), from changes in fair value and settlement of derivatives between the periods. The majority of the variance related to derivatives was due to non-cash favorable changes in fair value of our IPM agreements as a result of lower volatility in international gas prices and declines in international forward commodity curves, which changed from a loss of $5.0 billion in the year ended December 31, 2022 to a gain of $7.0 billion in the year ended December 31, 2023.

The favorable variance was partially offset by:

- decrease in LNG revenues, net of cost of sales and excluding the effect of derivatives (as further described above), of $2.4 billion, the majority of which was attributable to lower margins on LNG delivered;
- unfavorable variance of $2.1 billion in income tax provision due to higher taxable earnings; and
- unfavorable variance of $971 million in net income attributable to non-controlling interest due to an increase in CQP's consolidated net income between the comparable periods.

The following is an additional discussion of the significant drivers of the variance in net income attributable to common stockholders by line item:

Revenues

The decrease of $13.0 billion between the years ended December 31, 2023 and 2022 was primarily attributable to:

- $9.1 billion decrease in Henry Hub pricing, to which the majority of our long-term LNG sales contracts are indexed;

- decrease in revenues generated by our marketing function of $2.5 billion due to declining international prices and a reduction of volumes sold under short-term agreements; and
- decrease in regasification revenues of $933 million due to the accelerated recognition of revenues associated with the termination of one of our TUA agreements in December 2022. See Note 13—Revenues of our Notes to Consolidated Financial Statements for additional information on the termination agreement.

Operating costs and expenses (recoveries)

The $24.0 billion favorable variance between the years ended December 31, 2023 and 2022 was primarily attributable to:

- $14.0 billion favorable variance from changes in fair value and settlements of derivatives included in cost of sales, from $6.2 billion of loss in the year ended December 31, 2022 to $7.8 billion of gain in the year ended December 31, 2023, primarily related to non-cash favorable changes in fair value of our IPM agreements as described above under the caption *Net income attributable to common stockholders*; and
- $10.3 billion decrease in cost of sales excluding the effect of derivative changes described above, primarily as a result of $9.6 billion in decreased cost of natural gas feedstock largely due to lower U.S. natural gas prices.

The favorable variance was partially offset by an increase in operating and maintenance expense of $154 million between the comparable periods, which was due to the completion of planned large-scale maintenance activities on two trains at the SPL Project during June 2023, other third party service and maintenance contract costs and natural gas transportation and storage capacity demand charges.

Other income (expense)

The $554 million favorable variance between the years ended December 31, 2023 and 2022 was primarily attributable to:

- $265 million decrease in interest expense, net of capitalized interest, primarily as a result of lower debt balances due to $1.2 billion of repayment of debt in 2023, which excludes prepayments associated with debt refinancing;
- $154 million increase in interest and dividend income as a result of higher interest income earned on cash and cash equivalents from higher interest rates in 2023; and
- $81 million favorable variance in gain (loss) on modification or extinguishment of debt, primarily due to higher losses recognized from the amendment and restatement of CCH's term loan facility agreement (the **"CCH Credit Facility"**) and CCH's working capital facility agreement (the **"CCH Working Capital Facility"**) during the second quarter of 2022 and the redemption of our 4.25% Convertible Senior Notes due 2045 (the **"2045 Cheniere Convertible Senior Notes"**) during the first quarter of 2022. Further contributing to the favorable variance during the year ended December 31, 2023 was a reduction in premiums paid for the early redemption or repayment of debt principal, as a result of near-maturity debt being redeemed or repaid or repurchased in the open market resulting in lower make-whole payments, as further detailed under *Financing Cash Flows* in Sources and Uses of Cash within Liquidity and Capital Resources.

Income tax provision

The $2.1 billion unfavorable variance between the years ended December 31, 2023 and 2022 was primarily attributable to an increase in pre-tax income.

Our effective tax rate was 17.3% and 14.8% for the years ended December 31, 2023 and 2022, respectively. The effective tax rate for both the years ended December 31, 2023 and 2022 was lower than the statutory rate of 21% primarily due to CQP's income that is not taxable to us.

In December 2021, the OECD released a framework for Pillar Two model rules, which introduced a global minimum corporate tax rate of 15% for large multinational groups. We are a large multinational group with substantial operations in the U.S. and U.K. The U.K. enacted legislation implementing Pillar Two on July 18, 2023, effective beginning January 1, 2024. The U.S. has not enacted legislation implementing Pillar Two. We are continuing to evaluate the Pillar Two rules and their potential impact on future periods, but we do not expect the rules to have a material impact on our effective tax rate.

Net income attributable to non-controlling interest

The $971 million increase between the years ended December 31, 2023 and 2022 was primarily attributable to $1.8 billion increase in CQP's consolidated net income between the years ended December 31, 2023 and 2022.

Significant factors affecting our results of operations

Below are significant factors that affect our results of operations.

Gains and losses on derivative instruments

Derivative instruments, which in addition to managing exposure to commodity-related marketing and price risks, are utilized to manage exposure to changing interest rates and foreign exchange volatility, are reported at fair value on our Consolidated Financial Statements. For commodity derivative instruments related to our IPM agreements, the underlying LNG sales being economically hedged are accounted for under the accrual method of accounting, whereby revenues expected to be derived from the future LNG sales are recognized only upon delivery or realization of the underlying transaction. Notwithstanding the operational intent to mitigate risk exposure over time, the recognition of derivative instruments at fair value has the effect of recognizing gains or losses relating to future period exposure, and given the significant volumes, long-term duration and volatility in price basis for certain of our derivative contracts, the use of derivative instruments may result in continued volatility of our results of operations based on changes in market pricing, counterparty credit risk and other relevant factors that may be outside of our control. For example, as described in Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements, the fair value of our Liquefaction Supply Derivatives and LNG Trading Derivatives incorporates, as applicable to our natural gas supply contracts, market participant-based assumptions pertaining to certain contractual uncertainties, including those related to the availability of market information for delivery points, which may require future development of infrastructure, as well as the timing of both satisfaction of contractual events or states of affairs and delivery commencement. We may recognize changes in fair value through earnings that could be significant to our results of operations if and when such uncertainties are resolved.

Commissioning cargoes

Prior to substantial completion of a Train, amounts received from the sale of commissioning cargoes from that Train are offset against LNG terminal construction-in-process, because these amounts are earned or loaded during the testing phase for the construction of that Train. During the year ended December 31, 2022, we realized offsets to LNG terminal costs of $204 million corresponding to 15 TBtu attributable to the sale of commissioning cargoes from Train 6 of the SPL Project. We did not have any commissioning cargoes during the year ended December 31, 2023.

Liquidity and Capital Resources

The following information describes our ability to generate and obtain adequate amounts of cash to meet our requirements in the short term and the long term. In the short term, we expect to meet our cash requirements using operating cash flows and available liquidity, consisting of cash and cash equivalents, restricted cash and cash equivalents and available commitments under our credit facilities. Additionally, we expect to meet our long term cash requirements by using operating cash flows and other future potential sources of liquidity, which may include debt and equity offerings by us or our subsidiaries. The table below provides a summary of our available liquidity (in millions). Future material sources of liquidity are discussed below.

		December 31, 2023
Cash and cash equivalents (1)	$	4,066
Restricted cash and cash equivalents (1)		459
Available commitments under our credit facilities (2):		
SPL Revolving Credit Facility		720
CQP Revolving Credit Facility		1,000
CCH Credit Facility		3,260
CCH Working Capital Facility		1,345
Cheniere's revolving credit agreement (the **"Cheniere Revolving Credit Facility"**)		1,250
Total available commitments under our credit facilities		7,575
Total available liquidity	$	12,100

(1) Amounts presented include balances held by our consolidated variable interest entity, CQP, and its subsidiaries, as discussed in Note 9—Non-controlling Interest and Variable Interest Entity of our Notes to Consolidated Financial Statements. As of December 31, 2023, assets of CQP and its subsidiaries, which are included in our Consolidated Balance Sheets, included $575 million of cash and cash equivalents and $56 million of restricted cash and cash equivalents.

(2) Available commitments represent total commitments less loans outstanding and letters of credit issued under each of our credit facilities as of December 31, 2023. See Note 11—Debt of our Notes to Consolidated Financial Statements for additional information on our credit facilities and other debt instruments.

Our liquidity position subsequent to December 31, 2023 will be driven by future sources of liquidity and future cash requirements as further discussed under the caption *Future Sources and Uses of Liquidity*.

Although our sources and uses of cash are presented below from a consolidated standpoint, SPL, CQP, CCH and Cheniere operate with independent capital structures. Certain restrictions under debt and equity instruments executed by our subsidiaries limit each entity's ability to distribute cash, including the following:

- SPL and CCH are required to deposit all cash received into restricted cash and cash equivalents accounts under certain of their debt agreements. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the Liquefaction Projects and other restricted payments. In addition, SPL and CCH's operating costs are managed by our subsidiaries under affiliate agreements, which may require SPL and CCH to advance cash to the respective affiliates, however the cash remains restricted for operation and construction of the Liquefaction Projects;
- CQP is required under its partnership agreement to distribute to unitholders all available cash on hand at the end of a quarter less the amount of any reserves established by its general partner. Beginning with the distribution paid in the second quarter of 2022, quarterly distributions by CQP are currently comprised of a base amount plus a variable amount equal to the remaining available cash per unit, which takes into consideration, among other things, amounts reserved for annual debt repayment and capital allocation goals, anticipated capital expenditures to be funded with cash, and cash reserves to provide for the proper conduct of CQP's business;
- Our 48.6% limited partner interest, 100% general partner interest and incentive distribution rights in CQP limit our right to receive cash held by CQP to the amounts specified by the provisions of CQP's partnership agreement; and
- SPL and CCH are restricted by affirmative and negative covenants included in certain of their debt agreements in their ability to make certain payments, including distributions, unless specific requirements are satisfied.

Despite the restrictions noted above, we believe that sufficient flexibility exists within the Cheniere complex to enable each independent capital structure to meet its currently anticipated cash requirements. The sources of liquidity at SPL, CQP and CCH primarily fund the cash requirements of the respective entity, and any remaining liquidity not subject to restriction, as supplemented by unrestricted liquidity provided by Cheniere Marketing, is available to enable Cheniere to meet its cash requirements.

Future Sources and Uses of Liquidity

The following discussion of our future sources and uses of liquidity includes estimates that reflect management's assumptions and currently known market conditions and other factors as of December 31, 2023. Estimates are not guarantees of future performance and actual results may differ materially as a result of a variety of factors described in this annual report on Form 10-K.

Future Sources of Liquidity under Executed SPAs

As described in Items 1. and 2. Business and Properties, our long-term customer arrangements form the foundation of our business and provide us with significant, stable, long-term cash flows. Substantially all of our future revenues are contracted under SPAs and because many of these contracts have long-term durations, we are contractually entitled to significant future consideration under these contracts which has not yet been recognized as revenue. This future consideration is, in most cases, not yet legally due to us and was not reflected on our Consolidated Balance Sheets as of December 31, 2023. In addition, a significant portion of this future consideration is subject to variability as discussed more specifically below. We anticipate that this consideration will be available to meet liquidity needs in the future. The following table summarizes our estimate of future material sources of liquidity to be received from executed SPAs as of December 31, 2023 (in billions):

	Estimated Revenues Under Executed SPAs by Period (1) (2)			
	2024	**2025 - 2028**	**Thereafter**	**Total**
LNG revenues (fixed fees)	$ 6.3	$ 27.1	$ 77.6	$ 111.0
LNG revenues (variable fees) (3)	7.0	40.8	140.5	188.3
Total	$ 13.3	$ 67.9	$ 218.1	$ 299.3

(1) Agreements in force as of December 31, 2023 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2023. The timing of revenue recognition under GAAP may not align with cash receipts, although we do not consider the timing difference to be material. We may enter into contracts to sell LNG that are conditioned upon one or both of the parties achieving certain milestones such as reaching FID on a certain liquefaction Train, obtaining financing or achieving substantial completion of a Train and any related facilities. These contracts are included in the revenues above when the conditions are considered probable of being met.

(2) LNG revenues exclude revenues from contracts with original expected durations of one year or less. As of December 31, 2023, Cheniere Marketing had short term delivery commitments of approximately 88 TBtu of LNG to be delivered to third party customers in 2024. Fixed fees are fees that are due to us regardless of whether a customer exercises, in certain instances, their contractual right to not take delivery of an LNG cargo under the contract. Variable fees are receivable only in connection with LNG cargoes that are delivered.

(3) LNG revenues (variable fees) reflect the assumption of delivery of all contractual volumes, irrespective of any contractual right of non-delivery. LNG revenues (variable fees) are based on estimated forward prices and basis spreads as of December 31, 2023. The pricing structure of many of our SPA arrangements with our customers incorporates a variable fee per MMBtu of LNG generally equal to 115% of Henry Hub, which is paid upon delivery, thus limiting our net exposure to future increases in natural gas prices.

Through our SPAs and IPM agreements, we have contracted substantially all of the total anticipated production from the Liquefaction Projects through the mid-2030s. The majority of the contracted capacity is comprised of fixed-price, long-term SPAs that SPL and CCL have executed with third parties to sell LNG from the Liquefaction Projects. In addition, we market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL through our integrated marketing function, Cheniere Marketing. Cheniere Marketing has a portfolio of long-, medium- and short-term SPAs to deliver commercial LNG cargoes to locations worldwide. These volumes are expected to be primarily sourced by LNG produced by the Liquefaction Projects but supplemented by volumes procured from other locations worldwide, as needed.

Substantially all of our contracted capacity is from contracts with terms exceeding 10 years. Excluding volumes from contracts with terms less than 10 years and volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation, our SPAs and IPM agreements had approximately 16 years of weighted average remaining life as of December 31, 2023. Under the SPAs, the customers purchase LNG on either an FOB basis (delivered to the customer at the Sabine Pass LNG Terminal or the Corpus Christi LNG Terminal, as applicable) or a DAT basis (delivered to the customer at their specified LNG receiving terminal) generally for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG generally equal to 115% of Henry Hub. Certain customers may elect to cancel or suspend deliveries of LNG cargoes, with advance notice as governed by each respective SPA, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered as a result of such cancellation or suspension. The variable fees under our SPAs were generally sized with the intention to cover the costs of gas purchases, transportation and liquefaction fuel consumed to produce the LNG to be sold under each such SPA. Our long-term SPA customers consist of creditworthy counterparties, with an average credit rating of A-, A3 and A- by S&P, Moody's and Fitch, respectively. A discussion of revenues under our SPAs can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Additional Future Sources of Liquidity

Regasification Revenues

SPLNG has a long-term, third party TUA with TotalEnergies, under which TotalEnergies is required to pay fixed fees of approximately $125 million annually, whether or not it uses the regasification capacity it has reserved. SPL has a partial TUA assignment agreement with TotalEnergies, whereby SPL gained access to substantially all of TotalEnergies' capacity and other services provided under TotalEnergies' TUA with SPLNG. Notwithstanding any arrangements between TotalEnergies and SPL, payments required to be made by TotalEnergies to SPLNG will continue to be made by TotalEnergies to SPLNG in accordance with its TUA and we continue to recognize the payments received from TotalEnergies as revenue. Costs incurred by SPL to TotalEnergies under this partial TUA assignment agreement are recognized in operating and maintenance expense. Full discussion of the partial TUA assignment and SPLNG's revenues under the TUA agreements can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Available Commitments under Credit Facilities

As of December 31, 2023, we had $7.6 billion in available commitments under our credit facilities, as detailed earlier in the table summarizing our available liquidity, subject to compliance with the applicable covenants, to potentially meet liquidity needs. Our credit facilities mature between 2026 and 2029.

Uncontracted Liquefaction Supply

We expect a portion of total production capacity from the Liquefaction Projects that has not yet been contracted under executed agreements as of December 31, 2023 to be available for Cheniere Marketing to market to additional LNG customers. Debottlenecking opportunities and other optimization projects have led to increased run-rate production levels which has increased the production capacity available for Cheniere Marketing to the extent it has not already been contracted to other customers.

Financially Disciplined Growth

Our significant land positions at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal provide potential development and investment opportunities for further liquefaction capacity expansion at strategically advantaged locations with proximity to pipeline infrastructure and resources. In May 2023, certain subsidiaries of CQP entered the pre-filing review process with the FERC under the NEPA for the SPL Expansion Project. In March 2023, certain of our subsidiaries submitted an application with the FERC under the NGA for the CCL Midscale Trains 8 & 9 Project. The development of these sites or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, acceptable commercial and financing arrangements before we make a positive FID.

Future Cash Requirements for Operations and Capital Expenditures under Executed Contracts

We are committed to make future cash payments for operations and capital expenditures pursuant to certain of our contracts. The following table summarizes our estimate of material cash requirements for operations and capital expenditures related to our core operations under executed contracts as of December 31, 2023 (in billions):

	Estimated Payments Due Under Executed Contracts by Period (1)			
	2024	2025 - 2028	Thereafter	Total
Purchase obligations (2):				
Natural gas supply agreements (3)	$ 5.8	$ 20.2	$ 25.4	$ 51.4
Natural gas transportation and storage service agreements (4)	0.5	2.0	4.9	7.4
Capital expenditures	1.2	1.7	—	2.9
Leases (5)	0.9	3.0	3.7	7.6
Total	$ 8.4	$ 26.9	$ 34.0	$ 69.3

(1) Agreements in force as of December 31, 2023 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2023.

(2) Purchase obligations consist of agreements to purchase goods or services that are enforceable and legally binding that specify fixed or minimum quantities to be purchased. We include contracts for which we have an early termination option if the option is not currently expected to be exercised. We include contracts with unsatisfied contractual conditions if the conditions are currently expected to be met.

(3) Pricing of natural gas supply agreements is based on estimated forward prices and basis spreads as of December 31, 2023. Pricing of IPM agreements is based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Global gas market prices are based on estimates as of December 31, 2023 to the extent forward prices are not available and assume the highest price in cases of price optionality available under the agreement. Includes $0.8 billion under natural gas supply agreements with unsatisfied contractual conditions.

(4) Includes $1.3 billion of purchase obligations to related parties under the natural gas transportation and storage service agreements, of which $1.0 billion had unsatisfied contractual conditions.

(5) Leases include payments under (1) operating leases, (2) finance leases, (3) short-term leases and (4) vessel time charters that were executed as of December 31, 2023 but will commence in the future. Certain of our leases also contain variable payments, such as inflation, which are not included above unless the contract terms require in-substance fixed payments that are, in effect, unavoidable. Payments during renewal options that are exercisable at our sole discretion are included only to the extent that the option is believed to be reasonably certain to be exercised. We subcharter certain LNG vessels while retaining our existing obligation under the original charter. Future income associated with our subcharters was $510 million, inclusive of, as described in Note 12—Leases of our Notes to Consolidated Financial Statements, $163 million qualifying as subleases.

Natural Gas Supply, Transportation and Storage Service Agreements

We have secured natural gas feedstock for the CCL Project and the SPL Project through long-term natural gas supply agreements, including IPM agreements. Under our IPM agreements, we pay for natural gas feedstock based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. While IPM agreements are not revenue contracts for accounting purposes, the payment structure for the purchase of natural gas under the IPM agreements generates a take-or-pay style fixed liquefaction fee, assuming that LNG produced from the natural gas feedstock is subsequently sold at a price approximating the global gas market price paid for the natural gas feedstock purchase.

As of December 31, 2023, we have secured approximately 82% of the natural gas supply required to support the total forecasted production capacity of the Liquefaction Projects during 2024. Natural gas supply secured decreases as a percentage of forecasted production capacity beyond 2024. Natural gas supply is generally secured on an indexed pricing basis plus a fixed fee, with title transfer occurring upon receipt of the commodity. As further described in the *LNG Revenues* section above, the pricing structure of our SPA arrangements with our customers often incorporates a variable fee per MMBtu of LNG generally equal to 115% of Henry Hub, which is paid upon delivery, thus limiting our net exposure to future increases in natural gas prices. Inclusive of amounts under contracts with unsatisfied contractual conditions that are currently considered probable of being met and exclusive of extension options that were uncertain to be taken as of December 31, 2023, we have secured up to 12,794 TBtu of natural gas feedstock through agreements with remaining fixed terms of up to approximately 15 years. A discussion of our natural gas supply and IPM agreements can be found in Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements.

To ensure that we are able to transport natural gas feedstock to the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal, we have entered into transportation precedent and other agreements to secure firm pipeline transportation capacity from interstate and intrastate pipeline companies. We have also entered into firm storage services agreements with third parties to assist in managing variability in natural gas needs for the Liquefaction Projects.

Capital Expenditures

We enter into lump sum turnkey contracts with third party contractors for the EPC of our Liquefaction Projects. The future capital expenditures included in the table above primarily consist of fixed costs under the Bechtel EPC contract for the Corpus Christi Stage 3 Project, in which Bechtel charges a lump sum and generally bears project cost, schedule and performance risks unless certain specified events occurred, in which case Bechtel causes us to enter into a change order, or we agree with Bechtel to a change order. In addition to amounts presented in the table above, we expect to incur ongoing capital expenditures to maintain our facilities and other assets, as well as to optimize our existing assets and purchase new assets that are intended to grow our productive capacity. See *Financially Disciplined Growth* section for further discussion.

Corpus Christi Stage 3 Project

The following table summarizes the project completion and construction status of the Corpus Christi Stage 3 Project as of December 31, 2023:

Overall project completion percentage	51.4%
Completion percentage of:	
Engineering	83.7%
Procurement	72.2%
Subcontract work	66.9%
Construction	11.1%
Date of expected substantial completion	2Q/3Q 2025 - 2H 2026

Leases

Our obligations under our lease arrangements primarily consist of LNG vessel time charters with terms of up to 15 years to ensure delivery of cargoes sold on a DAT basis. We have also entered into leases for the use of tug vessels, office space, marine equipment and facilities and land sites. A discussion of our lease obligations can be found in Note 12—Leases of our Notes to Consolidated Financial Statements.

Additional Future Cash Requirements for Operations and Capital Expenditures

Corporate Activities

We are required to maintain corporate and general and administrative functions to serve our business activities. During the year ended December 31, 2023, selling, general and administrative expense was $0.5 billion, a portion of which was related to leases for office space, which is included in the table of cash requirements for operations and capital expenditures under executed contracts above.

Income Tax

Because the currently enacted CAMT may accelerate or cause volatility in our cash tax payments attributable to variability in AFSI, our cash tax payments may fluctuate over time, influenced by both AFSI variability and the resulting impact of the CAMT on other tax benefits, including potential near-term deferral of the realization of our existing NOL carryforwards. This could result in higher cash tax payments in the near-term relative to the year ended December 31, 2023. Additionally, our cash tax payments may be substantially lower in the periods that the Corpus Christi Stage 3 Project is placed into service due to anticipated tax depreciation allowances from the project. Thus, the ongoing interplay between the CAMT, the utilization of our existing NOLs and bonus depreciation eligibility of our Corpus Christi Stage 3 Project is expected to cause volatility in our cash tax payments. See the risk *Additions or changes in tax laws and regulations could potentially affect our financial results or liquidity* under *Risks Relating to Our Financial Matters* in Item 1A. Risk Factors.

Financially Disciplined Growth

The FID of any expansion projects will result in additional cash requirements to fund the construction and operations of such projects in excess of our current contractual obligations under executed contracts discussed above. However, in connection with reaching FID, we may be required to secure financing to meet the cash needs that such project will initially require, in support of commercializing the project.

Beyond the Corpus Christi Stage 3 Project, our significant land positions at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal provide potential development and investment opportunities for further liquefaction capacity expansion at strategically advantaged locations with proximity to pipeline infrastructure and resources. We expect that any potential future expansion at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal would increase cash requirements to support expanded operations, although expansion may be designed to leverage shared infrastructure to reduce the incremental costs of any potential expansion.

Future Cash Requirements for Financing under Executed Contracts

We are committed to make future cash payments for financing pursuant to certain of our contracts. The following table summarizes our estimate of material cash requirements for financing under executed contracts as of December 31, 2023 (in billions):

	Estimated Payments Due Under Executed Contracts by Period (1)			
	2024	2025 - 2028	Thereafter	Total
Debt	$ 0.3	$ 11.1	$ 12.5	$ 23.9
Interest payments	1.3	3.3	1.8	6.4
Total	$ 1.6	$ 14.4	$ 14.3	$ 30.3

(1) Debt and interest payments are based on the total debt balance, scheduled contractual maturities and fixed or estimated forward interest rates in effect at December 31, 2023. Debt and interest payments do not contemplate repurchases, repayments and retirements that we may make prior to contractual maturity.

Debt

As of December 31, 2023, our debt complex was comprised of senior notes with an aggregate outstanding principal balance of $23.9 billion and credit facilities with no outstanding loan balances. As of December 31, 2023, each of our issuers was in compliance with all covenants related to their respective debt agreements. Further discussion of our debt obligations, including the restrictions imposed by these arrangements, can be found in Note 11—Debt of our Notes to Consolidated Financial Statements.

Interest

As of December 31, 2023, our senior notes had a weighted average contractual interest rate of 4.73%. All of our existing credit facilities include a variable interest rate indexed to SOFR, incorporated through amendments or replacements of previous credit facilities. Undrawn commitments under our credit facilities are subject to commitment fees ranging from 0.075% to 0.525%, subject to change based on the applicable entity's credit rating. Issued letters of credit under our credit facilities are subject to letter of credit fees ranging from 1.000% to 2.200%, subject to change based on the applicable entity's credit rating. We had $435 million aggregate amount of issued letters of credit under our credit facilities as of December 31, 2023.

Additional Future Cash Requirements for Financing

CQP Distributions

CQP is required by its partnership agreement to, within 45 days after the end of each quarter, distribute to unitholders all available cash at the end of a quarter less the amount of any reserves established by its general partner. We own a 48.6% limited partner interest in CQP in the form of 239.9 million common units, 100% of the general partner interest and 100% of the incentive distribution rights, with the remaining non-controlling limited partner interest held by Blackstone Inc., Brookfield Asset Management Inc. and the public. During the year ended December 31, 2023, $1.0 billion in distributions were paid to our non-controlling interests.

Capital Allocation Plan

In September 2022, our Board approved a revised comprehensive long-term capital allocation plan. Pursuant to the revised capital allocation plan, on September 12, 2022 our Board authorized an increase in the existing share repurchase program by $4.0 billion for an additional three years, beginning on October 1, 2022. As of December 31, 2023, we had up to $2.1 billion available under the share repurchase program. The timing and amount of any shares of our common stock that are repurchased under the share repurchase program will be determined by management based on market conditions and other factors. During the year ended December 31, 2023, we repurchased a total of 9.5 million shares of our common stock for $1.5 billion at a weighted average price per share of $155.50. A discussion of our share repurchase program can be found in Item 5. Market for Registrant's Common Equity, Related Stockholders Matters and Issuer Purchase of Equity Securities.

A further aspect of our capital allocation plan is to lower our long-term leverage target through debt paydown to approximately 4x, which may involve the repayment, redemption or repurchase, on the open market or otherwise, of our indebtedness, including senior notes of SPL, CQP, CCH and Cheniere. The timing and amount of any paydown of our indebtedness will be determined by management based on market conditions and other factors. During the year ended December 31, 2023, we used $1.2 billion of available cash to reduce our outstanding indebtedness, all of which was pursuant to our capital allocation plan.

The capital allocation plan also includes a targeted annual dividend growth rate of approximately 10% through Corpus Christi Stage 3 Project construction. On January 26, 2024, we declared a quarterly dividend of $0.435 per share of common stock that is payable on February 23, 2024 to stockholders of record as of the close of business on February 6, 2024.

Financially Disciplined Growth

To the extent that liquefaction capacity at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal is expanded beyond the Liquefaction Projects, such as the CCL Midscale Trains 8 & 9 Project and the SPL Expansion Project, we expect that additional financing would be used to fund construction of the expansion.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash, cash equivalents and restricted cash and cash equivalents (in millions). The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals, which are referred to elsewhere in this report. Additional discussion of these items follows the table.

	Year Ended December 31,	
	2023	**2022**
Net cash provided by operating activities	$ 8,418	$ 10,523
Net cash used in investing activities	(2,202)	(1,844)
Net cash used in financing activities	(4,180)	(8,014)
Effect of exchange rate changes on cash, cash equivalents and restricted cash and cash equivalents	2	5
Net increase in cash, cash equivalents and restricted cash and cash equivalents	$ 2,038	$ 670

Operating Cash Flows

The $2.1 billion decrease between the periods was primarily related to lower cash receipts from the sale of LNG cargoes due to lower pricing per MMBtu as a result of decreased pricing and a reduction of volumes sold under short-term agreements, as well as a decrease in regasification revenues. A discussion of our revenues, including LNG and regasification revenues, can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements. The decrease was partially offset by lower cash outflows for natural gas feedstock, mostly due to lower U.S. natural gas prices.

As described in *Future Sources and Uses of Liquidity*, our future operating cash flows will be impacted by CAMT, which may result in greater volatility in our cash tax payments, including potentially higher cash payments in the near-term relative to the year ended December 31, 2023. See *Future Sources and Uses of Liquidity* for additional discussion.

Investing Cash Flows

Our investing net cash outflows in both years primarily were for the construction costs for the Liquefaction Projects. The $358 million increase in 2023 compared to 2022 was primarily due to $1.5 billion of cash outflows during the year ended December 31, 2023 related to construction of the Corpus Christi Stage 3 Project following our issuance of full notice to proceed to Bechtel in June 2022 compared to $880 million in the comparable period of 2022, partially offset by a decrease in spend due to the completion of Train 6 of the SPL Project in February 2022. We expect to incur a similar level of capital expenditures in the upcoming year as construction work progresses on the Corpus Christi Stage 3 Project. During the year ended December 31, 2023, we also made investments in infrastructure expected to support the development, construction and operations of the Corpus Christi Stage 3 Project, including an investment in pipeline capacity for natural gas feedstock. Also during the year ended December 31, 2023, we acquired an existing power generation facility located near Corpus Christi, Texas to mitigate power price risk associated with our anticipated increased power load at the Corpus Christi LNG Terminal.

Financing Cash Flows

The following table summarizes our financing activities (in millions):

	Year Ended December 31,	
	2023	**2022**
Proceeds from issuances of debt	$ 1,397	$ 1,575
Redemptions, repayments and repurchases of debt	(2,598)	(6,771)
Distributions to non-controlling interest	(1,016)	(947)
Repurchase of common stock	(1,473)	(1,373)
Dividends to stockholders	(393)	(349)
Other, net	(97)	(149)
Net cash used in financing activities	$ (4,180)	$ (8,014)

Debt Issuances

During the year ended December 31, 2023, CQP issued an aggregate principal amount of $1.4 billion of 2033 CQP Senior Notes, the proceeds of which were used, together with cash on hand, to redeem $1.4 billion of the 2024 SPL Senior Notes. Additionally, during the year ended December 31, 2023, SPL purchased $200 million of the 2024 SPL Senior Notes in the open market and redeemed an additional $100 million of the 2024 SPL Senior Notes. As of December 31, 2023, the only bonds maturing in 2024 are the remaining $300 million outstanding of the 2024 SPL Senior Notes. During the year ended December 31, 2022, SPL issued $430 million of 5.900% Senior Secured Amortizing Notes due 2037 and $70 million of 2037 SPL Private Placement Senior Secured Notes, and we had total borrowings of $1.1 billion under our credit facilities. The proceeds from the borrowings during the year ended December 31, 2022, together with cash on hand, were used to redeem or repurchase $6.8 billion of outstanding indebtedness, entirely associated with redemptions of our outstanding notes or repayment of amounts outstanding under our credit facilities.

Debt Redemptions, Repayments and Repurchases

The following table shows the redemptions, repayments and repurchases of debt, including intra-year repayments (in millions):

	Year Ended December 31, 2023	Year Ended December 31, 2022
Redemptions, repayments and repurchases of debt		
SPL:		
2024 SPL Senior Notes	$ (1,700)	$ —
2023 SPL Senior Notes	—	(1,500)
SPL Working Capital Facility	—	(60)
CCH:		
CCH Credit Facility	—	(2,169)
CCH Working Capital Facility	—	(250)
7.000% Senior Notes due 2024	(498)	(752)
5.625% Senior Notes due 2025	—	(9)
5.125% Senior Notes due 2027	(69)	(230)
3.700% Senior Notes due 2029	(237)	(138)
2.742% Senior Notes due 2039	(94)	—
3.788% weighted average Senior Notes rate due 2039	—	(88)
Cheniere:		
2045 Cheniere Convertible Senior Notes	—	(500)
Cheniere Revolving Credit Facility	—	(575)
4.625% Senior Notes due 2028	—	(500)
Total redemptions, repayments and repurchases of debt	$ (2,598)	$ (6,771)

Non-Controlling Interest Distributions

We own a 48.6% limited partner interest in CQP with the remaining non-controlling limited partner interest held by Blackstone Inc., Brookfield Asset Management Inc. and the public. Distributions of $1.0 billion and $947 million were paid during the years ended December 31, 2023 and 2022, respectively, to non-controlling interests.

Repurchase of Common Stock

During the years ended December 31, 2023 and 2022, we paid $1.5 billion and $1.4 billion to repurchase 9.5 million and 9.4 million shares of our common stock, respectively, under our share repurchase program. As of December 31, 2023, we had approximately $2.1 billion remaining under our share repurchase program.

Cash Dividends to Stockholders

During the year ended December 31, 2023, we paid aggregate dividends of $1.62 per share of common stock, for a total of $393 million. We paid aggregate dividends of $1.385 per share of common stock, for a total of $349 million during the year ended December 31, 2022.

On January 26, 2024, we declared a quarterly dividend of $0.435 per share of common stock that is payable on February 23, 2024 to stockholders of record as of the close of business on February 6, 2024.

Summary of Critical Accounting Estimates

The preparation of our Consolidated 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 regularly, including those related to the valuation of derivative instruments. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve significant judgment.

Fair Value of Level 3 Physical Liquefaction Supply Derivatives

All of our derivative instruments are recorded at fair value, as described in Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. We record changes in the fair value of our derivative positions through earnings, based on the value for which the derivative instrument could be exchanged between willing parties. Valuation of our physical liquefaction supply derivative contracts is often developed through the use of internal models which includes significant unobservable inputs representing Level 3 fair value measurements as further described in Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. In instances where observable data is unavailable, consideration is given to the assumptions that market participants may use in valuing the asset or liability. To the extent valued using an option pricing model, we consider the future prices of energy units for unobservable periods to be a significant unobservable input to estimated net fair value. In estimating the future prices of energy units, we make judgments about market risk related to liquidity of commodity indices and volatility utilizing available market data. Changes in facts and circumstances or additional information may result in revised estimates and judgments, and actual results may differ from these estimates and judgments. We derive our volatility assumptions based on observed historical settled global LNG market pricing or accepted proxies for global LNG market pricing as well as settled domestic natural gas pricing. Such volatility assumptions also contemplate, as of the balance sheet date, observable forward curve data of such indices, as well as evolving available industry data and independent studies. In developing our volatility assumptions, we acknowledge that the global LNG industry is inherently influenced by events such as unplanned supply constraints, geopolitical incidents, unusual climate events including drought and uncommonly mild, by historical standards, winters and summers, and real or threatened disruptive operational impacts to global energy infrastructure. Our current estimate of volatility does not exclude the impact of otherwise rare events unless we believe market participants would exclude such events on account of their assertion that those events were specific to our company and deemed within our control.

As applicable to our natural gas supply contracts, our fair value estimates incorporate market participant-based assumptions pertaining to applicable contractual uncertainties, including those related to the availability of market information for delivery points, as well as the timing of both satisfaction of contractual events or states of affairs and delivery commencement. We may recognize changes in fair value through earnings that could be significant to our results of operations if and when such uncertainties are resolved.

Additionally, the valuation of certain physical liquefaction supply derivatives requires significant judgment in estimating underlying forward commodity curves due to periods of unobservability or limited liquidity. Such valuations are more susceptible to variability particularly when markets are volatile. Provided below are the changes in fair value from valuation of instruments valued through the use of internal models which incorporate significant unobservable inputs for the years ended December 31, 2023 and 2022 (in millions), which entirely consisted of physical liquefaction supply derivatives. The changes in fair value shown are limited to instruments still held at the end of each respective period.

	Year Ended December 31,	
	2023	2022
Favorable (unfavorable) changes in fair value relating to instruments still held at the end of the period	$ 5,700	$ (6,493)

The changes in fair value on instruments held at the end of both years are primarily attributed to a significant variance in the estimated and observable forward international LNG commodity prices on our IPM agreements during the years ended December 31, 2023 and 2022.

The estimated fair value of level 3 derivatives recognized in our Consolidated Balance Sheets as of December 31, 2023 and 2022 amounted to a liability of $2.2 billion and $9.9 billion, respectively, consisting entirely of physical liquefaction supply derivatives.

The ultimate fair value of our derivative instruments is uncertain, and we believe that it is reasonably possible that a material change in the estimated fair value could occur in the near future, particularly as it relates to commodity prices given the level of volatility in the current year. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for further analysis of the sensitivity of the fair value of our derivatives to hypothetical changes in underlying prices.

Recent Accounting Standards

For a summary of recently issued accounting standards, see Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Marketing and Trading Commodity Price Risk

We have commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the SPL Project and the CCL Project, and associated economic hedges (collectively, the **"Liquefaction Supply Derivatives"**). We have also entered into physical and financial derivatives to hedge the exposure to the commodity markets in which we have contractual arrangements to purchase or sell physical LNG (collectively, **"LNG Trading Derivatives"**). In order to test the sensitivity of the fair value of the Liquefaction Supply Derivatives and the LNG Trading Derivatives to changes in underlying commodity prices, management modeled a 10% change in the commodity price for natural gas for each delivery location and a 10% change in the commodity price for LNG, respectively, as follows (in millions):

	December 31, 2023		December 31, 2022	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ (2,117)	$ 1,526	$ (10,019)	$ 2,249
LNG Trading Derivatives	10	12	(46)	15

See Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements for additional details about our commodity derivative instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY, INC. AND SUBSIDIARIES

MANAGEMENT'S REPORT TO THE STOCKHOLDERS OF CHENIERE ENERGY, INC.

Management's Report on Internal Control Over Financial Reporting

As management, we are responsible for establishing and maintaining adequate internal control over financial reporting for Cheniere Energy, Inc. and its subsidiaries (**"Cheniere"**). In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, we have conducted an assessment, including testing using the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (**"COSO"**). Cheniere's system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and, even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation.

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2023, based on criteria in *Internal Control—Integrated Framework (2013)* issued by the COSO.

Cheniere's independent registered public accounting firm, KPMG LLP, has issued an audit report on Cheniere's internal control over financial reporting as of December 31, 2023, which is contained in this Form 10-K.

Management's Certifications

The certifications of Cheniere's Chief Executive Officer and Chief Financial Officer required by the Sarbanes-Oxley Act of 2002 have been included as Exhibits 31 and 32 in Cheniere's Form 10-K.

CHENIERE ENERGY, INC.

By:	/s/ Jack A. Fusco	By:	/s/ Zach Davis
	Jack A. Fusco		Zach Davis
	President and Chief Executive Officer (Principal Executive Officer)		Executive Vice President and Chief Financial Officer (Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Cheniere Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries (the Company) as of December 31, 2023 and 2022, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated 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 years in the three-year period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 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 21, 2024 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

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

Fair value of the level 3 liquefaction supply derivatives

As discussed in Notes 2 and 7 to the consolidated financial statements, the Company recorded fair value of level 3 liquefaction supply derivatives of $(2,178) million as of December 31, 2023, which included the fair value of IPM agreements. The IPM agreements are natural gas supply contracts for the operation of the liquefied natural gas facilities. The fair value of the IPM agreements is developed using internal models, including option pricing models. The models incorporate significant unobservable inputs, including future prices of energy units in unobservable periods and volatility.

We identified the evaluation of the fair value of the level 3 liquefaction supply derivatives for certain IPM agreements as a critical audit matter. Specifically, complex auditor judgment and specialized skills and knowledge were required to evaluate the appropriateness and application of the option pricing model as well as the assumptions for future prices of energy units in unobservable periods and volatility.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the valuation of liquefaction supply derivatives, including those under certain IPM agreements. This included controls related to the appropriateness and application of the option pricing model and the evaluation of assumptions for future prices of energy units in unobservable periods and volatility. We involved valuation professionals with specialized skills and knowledge who assisted in testing management's process for developing the fair value of certain IPM agreements by:

- evaluating the design and testing the operating effectiveness of certain internal controls related to the appropriateness and application of the option pricing model
- evaluating the appropriateness and application of the option pricing model by inspecting the contractual agreements and model documentation to determine whether the model is suitable for its intended use
- evaluating the reasonableness of management's assumptions for future prices of energy units in unobservable periods and volatility by comparing to market data.

/s/ KPMG LLP

KPMG LLP

We have served as the Company's auditor since 2014.

Houston, Texas
February 21, 2024

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Cheniere Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Cheniere Energy, Inc. and subsidiaries' (the Company) 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. 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 the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements), and our report dated February 21, 2024 expressed an unqualified opinion on those consolidated 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ KPMG LLP

KPMG LLP

Houston, Texas
February 21, 2024

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Year Ended December 31,		
	2023	2022	2021
Revenues			
LNG revenues	$ 19,569	$ 31,804	$ 15,395
Regasification revenues	135	1,068	269
Other revenues	690	556	200
Total revenues	20,394	33,428	15,864
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	1,356	25,632	13,773
Operating and maintenance expense	1,835	1,681	1,444
Selling, general and administrative expense	474	416	325
Depreciation and amortization expense	1,196	1,119	1,011
Other	44	21	12
Total operating costs and expenses	4,905	28,869	16,565
Income (loss) from operations	15,489	4,559	(701)
Other income (expense)			
Interest expense, net of capitalized interest	(1,141)	(1,406)	(1,438)
Gain (loss) on modification or extinguishment of debt	15	(66)	(116)
Interest and dividend income	211	57	3
Other income (expense), net	4	(50)	(26)
Total other expense	(911)	(1,465)	(1,577)
Income (loss) before income taxes and non-controlling interest	14,578	3,094	(2,278)
Less: income tax provision (benefit)	2,519	459	(713)
Net income (loss)	12,059	2,635	(1,565)
Less: net income attributable to non-controlling interest	2,178	1,207	778
Net income (loss) attributable to common stockholders	$ 9,881	$ 1,428	$ (2,343)
Net income (loss) per share attributable to common stockholders—basic (1)	$ 40.99	$ 5.69	$ (9.25)
Net income (loss) per share attributable to common stockholders—diluted (1)	$ 40.72	$ 5.64	$ (9.25)
Weighted average number of common shares outstanding—basic	241.0	251.1	253.4
Weighted average number of common shares outstanding—diluted	242.6	253.4	253.4

(1) Earnings per share in the table may not recalculate exactly due to rounding because it is calculated based on whole numbers, not the rounded numbers presented.

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (1)

(in millions, except share data)

	December 31,	
	2023	2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,066	$ 1,353
Restricted cash and cash equivalents	459	1,134
Trade and other receivables, net of current expected credit losses	1,106	1,944
Inventory	445	826
Current derivative assets	141	120
Margin deposits	18	134
Other current assets, net	96	97
Total current assets	6,331	5,608
Property, plant and equipment, net of accumulated depreciation	32,456	31,528
Operating lease assets	2,641	2,625
Derivative assets	863	35
Deferred tax assets	26	864
Other non-current assets, net	759	606
Total assets	$ 43,076	$ 41,266
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities		
Accounts payable	$ 181	$ 124
Accrued liabilities	1,780	2,679
Current debt, net of discount and debt issuance costs	300	813
Deferred revenue	179	234
Current operating lease liabilities	655	616
Current derivative liabilities	750	2,301
Other current liabilities	43	28
Total current liabilities	3,888	6,795
Long-term debt, net of discount and debt issuance costs	23,397	24,055
Operating lease liabilities	1,971	1,971
Finance lease liabilities	467	494
Derivative liabilities	2,378	7,947
Deferred tax liabilities	1,545	—
Other non-current liabilities	410	175
Commitments and contingencies (see Note 20)		
Stockholders' equity (deficit)		
Preferred stock: $0.0001 par value, 5.0 million shares authorized, none issued	—	—
Common stock: $0.003 par value, 480.0 million shares authorized; 277.9 million shares and 276.7 million shares issued at December 31, 2023 and 2022, respectively	1	1
Treasury stock: 40.9 million shares and 31.2 million shares at December 31, 2023 and 2022, respectively, at cost	(3,864)	(2,342)
Additional paid-in-capital	4,377	4,314
Accumulated income (deficit)	4,546	(4,942)
Total Cheniere stockholders' equity (deficit)	5,060	(2,969)
Non-controlling interest	3,960	2,798
Total stockholders' equity (deficit)	9,020	(171)
Total liabilities and stockholders' equity (deficit)	$ 43,076	$ 41,266

(1) Amounts presented include balances held by our consolidated variable interest entity (**"VIE"**), CQP, as further discussed in Note 9—Non-controlling Interest and Variable Interest Entity. As of December 31, 2023, total assets and liabilities of CQP were $17.7 billion and $18.8 billion, respectively, including $575 million of cash and cash equivalents and $56 million of restricted cash and cash equivalents.

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

(in millions)

	Total Stockholders' Equity (Deficit)							
	Common Stock		Treasury Stock					
	Shares	Par Value Amount	Shares	Amount	Additional Paid-in Capital	Accumulated Income (Deficit)	Non-controlling Interest	Total Equity (Deficit)
Balance at December 31, 2020	252.3	$ 1	20.8	$ (872)	$ 4,273	$ (3,593)	$ 2,409	$ 2,218
Vesting of share-based compensation awards	2.1	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	105	—	—	105
Issued shares withheld from employees related to share-based compensation, at cost	(0.7)	—	0.7	(47)	(1)	—	—	(48)
Shares repurchased, at cost	(0.1)	—	0.1	(9)	—	—	—	(9)
Net income attributable to non-controlling interest	—	—	—	—	—	—	778	778
Distributions and dividends to non-controlling interest	—	—	—	—	—	—	(649)	(649)
Dividends declared ($0.33 per common share)	—	—	—	—	—	(85)	—	(85)
Net loss attributable to common stockholders	—	—	—	—	—	(2,343)	—	(2,343)
Balance at December 31, 2021	253.6	1	21.6	(928)	4,377	(6,021)	2,538	(33)
Vesting of share-based compensation awards	1.5	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	112	—	—	112
Issued shares withheld from employees related to share-based compensation, at cost	(0.3)	—	0.3	(41)	(22)	—	—	(63)
Shares repurchased, at cost	(9.3)	—	9.3	(1,373)	—	—	—	(1,373)
Adoption of ASU 2020-06, net of tax	—	—	—	—	(153)	4	—	(149)
Net income attributable to non-controlling interest	—	—	—	—	—	—	1,207	1,207
Distributions to non-controlling interest	—	—	—	—	—	—	(947)	(947)
Dividends declared ($1.385 per common share)	—	—	—	—	—	(353)	—	(353)
Net income attributable to common stockholders	—	—	—	—	—	1,428	—	1,428
Balance at December 31, 2022	245.5	1	31.2	(2,342)	4,314	(4,942)	2,798	(171)
Vesting of share-based compensation awards	1.2	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	100	—	—	100
Issued shares withheld from employees related to share-based compensation, at cost	(0.2)	—	0.2	(26)	(37)	—	—	(63)
Shares repurchased, at cost	(9.5)	—	9.5	(1,496)	—	—	—	(1,496)
Net income attributable to non-controlling interest	—	—	—	—	—	—	2,178	2,178
Distributions to non-controlling interest	—	—	—	—	—	—	(1,016)	(1,016)
Dividends declared ($1.62 per common share)	—	—	—	—	—	(393)	—	(393)
Net income attributable to common stockholders	—	—	—	—	—	9,881	—	9,881
Balance at December 31, 2023	237.0	$ 1	40.9	$ (3,864)	$ 4,377	$ 4,546	$ 3,960	$ 9,020

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2023	2022	2021
Cash flows from operating activities			
Net income (loss)	$ 12,059	$ 2,635	$ (1,565)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized foreign currency exchange gain, net	(2)	(5)	—
Depreciation and amortization expense	1,196	1,119	1,011
Share-based compensation expense	250	205	140
Amortization of debt issuance costs, premium and discount	44	57	72
Reduction of right-of-use assets	623	607	393
Loss (gain) on modification or extinguishment of debt	(15)	66	116
Total losses (gains) on derivative instruments, net	(7,890)	6,531	5,989
Net cash used for settlement of derivative instruments	(79)	(904)	(1,579)
Deferred taxes	2,389	440	(715)
Repayment of paid-in-kind interest related to repurchase of convertible notes	—	(13)	(190)
Other, net	20	92	52
Changes in operating assets and liabilities:			
Trade and other receivables	840	(502)	(799)
Inventory	377	(123)	(409)
Margin deposits	116	631	(741)
Accounts payable and accrued liabilities	(982)	250	1,144
Total deferred revenue	3	124	55
Total operating lease liabilities	(607)	(622)	(418)
Other, net	76	(65)	(87)
Net cash provided by operating activities	8,418	10,523	2,469
Cash flows from investing activities			
Property, plant and equipment, net	(2,121)	(1,830)	(966)
Proceeds from sale of property, plant and equipment	—	1	68
Investment in equity method investments	(61)	(15)	—
Other, net	(20)	—	(14)
Net cash used in investing activities	(2,202)	(1,844)	(912)
Cash flows from financing activities			
Proceeds from issuances of debt	1,397	1,575	5,911
Redemptions, repayments and repurchases of debt	(2,598)	(6,771)	(6,810)
Distributions to non-controlling interest	(1,016)	(947)	(649)
Payments related to tax withholdings for share-based compensation	(63)	(63)	(48)
Repurchase of common stock	(1,473)	(1,373)	(9)
Dividends to stockholders	(393)	(349)	(85)
Other, net	(34)	(86)	(127)
Net cash used in financing activities	(4,180)	(8,014)	(1,817)
Effect of exchange rate changes on cash, cash equivalents and restricted cash and cash equivalents	2	5	—
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	2,038	670	(260)
Cash, cash equivalents and restricted cash and cash equivalents—beginning of period	2,487	1,817	2,077
Cash, cash equivalents and restricted cash and cash equivalents—end of period	$ 4,525	$ 2,487	$ 1,817

Balances per Consolidated Balance Sheets:

	December 31, 2023	December 31, 2022
Cash and cash equivalents	$ 4,066	$ 1,353
Restricted cash and cash equivalents	459	1,134
Total cash, cash equivalents and restricted cash and cash equivalents	$ 4,525	$ 2,487

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

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

We operate two natural gas liquefaction and export facilities located in Cameron Parish, Louisiana at Sabine Pass and near Corpus Christi, Texas (respectively, the **"Sabine Pass LNG Terminal"** and **"Corpus Christi LNG Terminal"**).

CQP owns the Sabine Pass LNG Terminal, which has natural gas liquefaction facilities consisting of six operational Trains, for a total production capacity of approximately 30 mtpa of LNG (the **"SPL Project"**). The Sabine Pass LNG Terminal also has operational regasification facilities that include five LNG storage tanks, vaporizers and three marine berths. We also own and operate a 94-mile natural gas supply pipeline that interconnects the Sabine Pass LNG Terminal with several interstate and intrastate pipelines (the **"Creole Trail Pipeline"**). As of December 31, 2023, we owned 100% of the general partner interest, a 48.6% limited partner interest and 100% of the incentive distribution rights of CQP.

The Corpus Christi LNG Terminal currently has three operational Trains for a total production capacity of approximately 15 mtpa of LNG, three LNG storage tanks and two marine berths. Additionally, we are constructing an expansion of the Corpus Christi LNG Terminal (the **"Corpus Christi Stage 3 Project"**) for seven midscale Trains with an expected total production capacity of over 10 mtpa of LNG. We also own a 21.5-mile natural gas supply pipeline that interconnects the Corpus Christi LNG Terminal with several interstate and intrastate natural gas pipelines (the **"Corpus Christi Pipeline"** and together with the Trains, storage tanks, and marine berths at the Corpus Christi LNG Terminal and the Corpus Christi Stage 3 Project, the **"CCL Project"**).

We are pursuing expansion projects to provide additional liquefaction capacity at the SPL Project and the CCL Project (collectively, the **"Liquefaction Projects"**), and we have commenced commercialization to support the additional liquefaction capacity associated with these expansion projects.

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 Cheniere, its subsidiaries and affiliates in which we hold a controlling interest. Additionally, we consolidate VIEs under certain criteria discussed further below. All intercompany accounts and transactions have been eliminated in consolidation.

VIEs

We make a determination at the inception of each arrangement whether an entity in which we have made an investment or in which we have other variable interests is considered a VIE. Generally, an entity is a VIE if either (1) the entity does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, (2) the entity's investors lack any characteristics of a controlling financial interest or (3) the entity was established with non-substantive voting rights.

We consolidate VIEs when we are deemed to be the primary beneficiary. The primary beneficiary of a VIE is generally the party that both: (1) has the power to make decisions that most significantly affect the economic performance of the VIE and (2) has the obligation to absorb losses or the right to receive benefits that in either case could potentially be significant to the VIE. If we are not deemed to be the primary beneficiary of a VIE, we account for the investment or other variable interests in a VIE in accordance with applicable GAAP.

Non-controlling Interests

When we consolidate an entity, we include 100% of the assets, liabilities, revenues and expenses of the subsidiary in our Consolidated Financial Statements. For those entities that we consolidate in which our ownership is less than 100%, we record a non-controlling interest as a component of equity on our Consolidated Balance Sheets, which represents the third party ownership in the net assets of the respective consolidated subsidiary. Additionally, the portion of the net income or loss attributable to the non-controlling interest is reported as net income attributable to non-controlling interest on our Consolidated Statements of Operations. Changes in our ownership interests in an entity that do not result in deconsolidation are generally recognized within equity. See Note 9—Non-controlling Interest and Variable Interest Entities for additional details about our non-controlling interest.

Estimates

The preparation of our Consolidated 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 regularly, including those related to fair value measurements of derivatives and other instruments, useful lives of property, plant and equipment and certain valuations including leases, asset retirement obligations (**"AROs"**) and recoverability of deferred tax assets, each as further discussed under the respective sections within this note. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Measurements

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. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation approaches used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs that are directly or indirectly observable for the asset or liability, other than quoted prices included within Level 1. Hierarchy Level 3 inputs are inputs that are not observable in the market.

In determining fair value, we use observable market data when available, or models that incorporate observable market data. In addition to market information, we incorporate transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value. We attempt to maximize our use of observable inputs and minimize our use of unobservable inputs in arriving at fair value estimates.

Recurring fair-value measurements are performed for derivative instruments, as disclosed in Note 7—Derivative Instruments, and liability-classified share-based compensation awards, as disclosed in Note 16—Share-Based Compensation.

The carrying amount of cash and cash equivalents, restricted cash and cash equivalents, trade and other receivables, net of current expected credit losses, contract assets, margin deposits, accounts payable and accrued liabilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount we would have to pay to repurchase our debt in the open market, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Refer to Note 11—Debt for our debt fair value estimates, including our estimation methods.

Revenue Recognition

We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration to which we expect to be entitled to in exchange for those goods or services. See Note 13—Revenues for further discussion of our revenue streams and accounting policies related to revenue recognition.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents consist of funds that are contractually or legally restricted as to usage or withdrawal and have been presented separately from cash and cash equivalents on our Consolidated Balance Sheets.

Current Expected Credit Losses

Current expected credit losses consider the risk of loss based on past events, current conditions and reasonable and supportable forecasts. A counterparty's ability to pay is assessed through a credit review process that considers payment terms, the counterparty's established credit rating or our assessment of the counterparty's credit worthiness, contract terms, payment status and other risks or available financial assurances. We record charges and reversals of current expected credit losses in selling, general and administrative in our Consolidated Statements of Operations.

The following table reflects the changes in our current expected credit losses (in millions):

	Year Ended December 31,		
	2023	2022	2021
Current expected credit losses, beginning of period	$ 5	$ 9	$ 7
Charges (reversals)	(2)	(4)	2
Current expected credit losses, end of period	$ 3	$ 5	$ 9

Inventory

LNG and natural gas inventory are recorded at the lower of weighted average cost and net realizable value. Materials and other inventory are recorded at the lower of cost and net realizable value. Inventory is charged to expense when sold, or, for certain qualifying costs, capitalized to property, plant and equipment when issued, primarily using the weighted average method.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction and commissioning activities, major renewals and betterments that extend the useful life of an asset are capitalized, while expenditures for maintenance and repairs (including those for planned major maintenance projects) to maintain property, plant and equipment in operating condition are generally expensed as incurred.

Generally, we begin capitalizing the costs of our LNG terminals once the individual project meets the following criteria: (1) regulatory approval has been received, (2) financing for the project is available and (3) management has committed to commence construction. Prior to meeting these criteria, most of the costs associated with a project are expensed as incurred. These costs primarily include professional fees associated with preliminary review and selection of equipment alternatives, costs of securing necessary regulatory approvals and other preliminary investigation and development activities related to our LNG terminals.

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land acquisition costs, detailed engineering design work and certain permits that are capitalized as other non-current assets.

We realize offsets to LNG terminal costs for sales of commissioning cargoes that were earned or loaded prior to the start of commercial operations of the respective Train during the testing phase for its construction.

We depreciate our property, plant and equipment using the straight-line depreciation method over assigned useful lives, except land which is not depreciated. Refer to Note 6—Property, Plant and Equipment, Net of Accumulated Depreciation for additional discussion of our useful lives by asset category. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed from the account, and the resulting gains or losses on disposal are recorded in other operating costs and expenses.

Management tests property, plant and equipment for impairment whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets for purposes of assessing recoverability. Recoverability generally is determined by comparing the carrying value of the asset to the expected undiscounted future cash flows of the asset. If the carrying value of the asset is not recoverable, the amount of impairment loss is measured as the excess, if any, of the carrying value of the asset over its estimated fair value.

We did not record any material impairments related to property, plant and equipment during the years ended December 31, 2023, 2022 and 2021.

Advances of Cash and Conveyed Assets to Service Providers

We may convey cash or physical assets to service providers in support of infrastructure maintained by them, which is necessary to support our own operations. Such conveyances are recognized within other non-current assets on our Consolidated Balance Sheets and amortized within depreciation and amortization expense on our Consolidated Statements of Operations over the shorter of the contractual term of the arrangement with the service provider or the useful life of the physical asset. The weighted average amortization period of these assets was approximately 31 years as of both December 31, 2023 and 2022.

Interest Capitalization

We capitalize interest costs mainly during the construction period of our LNG terminals and related assets. Upon placing the underlying asset in service, these costs are depreciated over the estimated useful life of the corresponding assets which interest costs were incurred, except for capitalized interest associated with land, which is not depreciated.

Derivative Instruments

We use derivative instruments to hedge our exposure to cash flow variability from commodity price and foreign currency exchange (**"FX"**) rate risk. Derivative instruments are recorded at fair value and included in our Consolidated Balance Sheets as current or non-current assets or liabilities depending on the derivative position and the expected timing of settlement. When we have the contractual right and intent to net settle, derivative assets and liabilities are reported on a net basis.

Changes in the fair value of our derivative instruments are recorded in earnings. We did not have any derivative instruments designated as cash flow, fair value or net investment hedges during the years ended December 31, 2023, 2022 and 2021. See Note 7—Derivative Instruments for additional details about our derivative instruments.

Leases

We determine if an arrangement is, or contains, a lease at inception of the arrangement. When we determine the arrangement is, or contains, a lease in which we are the lessee, we classify the lease as either an operating lease or a finance lease. Operating and finance leases are recognized 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.

Operating and finance lease right-of-use assets and liabilities are generally recognized based on the present value of minimum lease payments over the lease term. In determining the present value of minimum lease payments, we use the implicit interest rate in the lease if readily determinable. In the absence of a readily determinable implicit interest rate, we discount our expected future lease payments using our relevant subsidiary's incremental borrowing rate. The incremental borrowing rate is an estimate of the interest rate that a given subsidiary would have to pay to borrow on a collateralized basis over a similar term to that of the lease term. 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.

We have elected practical expedients to (1) omit leases with an initial term of 12 months or less from recognition on our balance sheet and (2) to combine both the lease and non-lease components of an arrangement in calculating the right-of-use asset and lease liability for all classes of leased assets.

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 using the effective interest method over the lease term.

Certain of our leases also contain variable payments that are included in the right-of-use asset and lease liability only when the payments are in-substance fixed payments that are, in effect, unavoidable.

When we determine the arrangement is, or contains, a lease in which we are the lessor or sublessor, we assess classification of the lease as either an operating lease, sales-type lease or direct financing lease. All of our arrangements have been assessed as operating leases and consist of sublessor arrangements in which we have not been relieved of our primary obligation under the original lease. Our sublessor arrangements are not recognized on our Consolidated Balance Sheets and we recognize income from these arrangements on a straight-line basis over the sublease term.

Concentration of Credit Risk

Financial instruments that potentially subject us to a concentration of credit risk consist principally of derivative instruments and accounts receivable and contract assets related to our long-term SPAs and regasification contracts, each discussed further below. Additionally, we maintain cash balances at financial institutions, which may at times be in excess of federally insured levels. We have not incurred credit losses related to these cash balances to date.

The use of derivative instruments exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. Certain of our commodity derivative transactions are executed through over-the-counter contracts which are subject to nominal credit risk as these transactions are settled on a daily margin basis with investment grade financial institutions. Collateral deposited for such contracts is recorded within margin deposits on our Consolidated Balance Sheets. Our FX derivative instruments are placed with investment grade financial institutions whom we believe are acceptable credit risks. We monitor counterparty creditworthiness on an ongoing basis; however, we cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, we may not realize the benefit of some of our derivative instruments.

We have contracted our anticipated production capacity under SPAs and under IPM agreements. Substantially all of our contracted capacity is from contracts with terms exceeding 10 years. As of December 31, 2023, we had SPAs with initial terms of 10 or more years with a total of 29 different third party customers. Excluding volumes from contracts with terms less than 10 years and volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation, our SPAs and IPM agreements had approximately 16 years of weighted average remaining life as of December 31, 2023. We market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL's customers through our integrated marketing function. We are dependent on the respective customers' creditworthiness and their willingness to perform under their respective agreements.

Our arrangements with our customers incorporate certain provisions to mitigate our exposure to credit losses and include, under certain circumstances, customer collateral, netting of exposures through the use of industry standard commercial agreements and, as described above, margin deposits with certain counterparties in the over-the-counter derivative market, with such margin deposits primarily facilitated by independent system operators and by clearing brokers. Payments on margin deposits, either by us or by the counterparty depending on the position, are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us (or to the counterparty) on or near the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions.

Debt

Our debt consists of current and long-term secured and unsecured debt securities and credit facilities with banks and other lenders. Debt issuances are placed directly by us or through securities dealers or underwriters and are held by institutional and retail investors.

Debt is recorded on our Consolidated Balance Sheets at par value adjusted for unamortized discount or premium and net of unamortized debt issuance costs related to term notes. Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees, printing costs and in certain cases, commitment fees. If debt issuance costs are incurred in connection with a line of credit arrangement or on undrawn funds, the debt issuance costs are presented as an asset on our Consolidated Balance Sheets. Discounts, premiums and debt issuance costs directly related to the issuance of debt are amortized over the life of the debt and are recorded in interest expense, net of capitalized interest using the effective interest method.

We classify debt on our Consolidated Balance Sheets based on contractual maturity, with the following exceptions:

- We classify term debt that is contractually due within one year as long-term debt if management has the intent and ability to refinance the current portion of such debt with future cash proceeds from an executed long-term debt agreement.
- We evaluate the classification of long-term debt extinguished after the balance sheet date but before the financial statements are issued based on facts and circumstances existing as of the balance sheet date.

Asset Retirement Obligations

We recognize AROs for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and for conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. The fair value of a liability for an ARO is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

We have not recorded an ARO associated with the Sabine Pass LNG Terminal. Based on the real property lease agreements at the Sabine Pass LNG Terminal, at the expiration of the term of the leases we are required to surrender the LNG terminal in good working order and repair, with normal wear and tear and casualty expected. Our property lease agreements at the Sabine Pass LNG Terminal have terms of up to 90 years including renewal options. We have determined that the cost to surrender the Sabine Pass LNG Terminal in good order and repair, with normal wear and tear and casualty expected, is immaterial.

We have not recorded an ARO associated with the Creole Trail Pipeline or the Corpus Christi Pipeline. We believe that it is not feasible to predict when the natural gas transportation services provided by the Creole Trail Pipeline or the Corpus Christi Pipeline will no longer be utilized. In addition, our right-of-way agreements associated with the Creole Trail Pipeline and the Corpus Christi Pipeline have no stipulated termination dates. We intend to operate the Creole Trail Pipeline and the Corpus Christi Pipeline as long as supply and demand for natural gas exists in the United States and intend to maintain it regularly.

Share-based Compensation

We have awarded share-based compensation in the form of restricted stock shares, restricted stock units, performance stock units and phantom units. The awards and our related accounting policies are more fully described in Note 16—Share-based Compensation.

Foreign Currency

The functional currency of all of our subsidiaries is the U.S. dollar. Certain of our subsidiaries transact in currencies outside of the U.S. dollar, which gives rise to the recognition of transaction gains and losses based on the change in exchange rates between the U.S. dollar and the currency in which the foreign currency transaction is denominated. During the years ended December 31, 2023, 2022 and 2021, we recognized net transaction gains (losses) totaling $(20) million, $60 million and $33 million, respectively, substantially all of which related to commercial transactions executed by Cheniere Marketing. The transaction gains and losses on such commercial transactions primarily consisted of those on Euro denominated receivables and related foreign currency hedges arising from the sale of cargoes, which are presented within LNG revenues in our Consolidated Statements of Operations with the underlying activities. The remaining transaction gains and losses are presented primarily within other income (expense), net in our Consolidated Statements of Operations.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the tax basis of assets and liabilities and their reported amounts in our Consolidated Financial Statements. Deferred tax assets and liabilities are included in our Consolidated Financial Statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled.

As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the current period's provision for income taxes.

A valuation allowance is recorded to reduce the carrying value of our deferred tax assets when it is more likely than not that some or all of our deferred tax assets will not be realized. We evaluate the realizability of our deferred tax assets as of each reporting date, weighing all positive and negative evidence. The assessment requires significant judgment and is performed in each of our applicable jurisdictions. In making such determination, we consider various factors such as historical profitability, future projections of sustained profitability underpinned by fixed-price long-term SPAs and reversal of existing deferred tax liabilities.

We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination.

We account for our federal investment tax credits under the flow-through method.

The Inflation Reduction Act of 2022 (**"IRA"**) imposes a 15% CAMT effective in 2023, that is based on 15% of an applicable corporation's adjusted financial statement income. We have elected to account for the effects of the CAMT on deferred tax assets, carryforwards and tax credits in the period they arise.

Net Income (Loss) Per Share

Basic net income or loss per share attributable to common stockholders excludes dilution and is computed by dividing net income or loss attributable to common stockholders during the period by the weighted average number of common shares outstanding during the period. Diluted net income or loss per share reflects potential dilution and is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares outstanding during the period, which is increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued. However, if the effect of any additional securities are anti-dilutive (i.e., resulting in a higher net income per share or lower net loss per share), they are excluded from the dilutive net income or loss computation. The dilutive effect of unvested stock is calculated using the treasury-stock method.

Refer to Note 18—Net Income (Loss) per Share Attributable to Common Stockholders for additional details of the computation for the years ended December 31, 2023, 2022 and 2021.

Business Segment

We have determined that we operate as a single operating and reportable segment. Substantially all of our long-lived assets are located in the United States. Our chief operating decision maker is regularly provided with consolidated financial information to makes resource allocation decisions and assesses performance in the delivery of an integrated source of LNG to our customers. The financial measures regularly provided to the chief operating decision maker that are most consistent with GAAP are net income (loss) attributable to common stockholders and total consolidated assets, as presented in our Consolidated Financial Statements.

Recent Accounting Standards

ASU 2020-04

In March 2020, the FASB issued ASU No. 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*. This guidance primarily provides temporary optional expedients which simplify the accounting for contract modifications to existing contracts as a result of the market transition from LIBOR to alternative reference rates. The temporary optional expedients under the standard became effective March 12, 2020 and will be available until December 31, 2024 following a subsequent amendment to the standard.

As further detailed in Note 11—Debt, all of our existing credit facilities include a variable interest rate indexed to SOFR, incorporated through amendments or replacements of previous credit facilities subsequent to the effective date of ASU 2020-04. We elected to apply the optional expedients as applicable to certain modified or replaced facilities; however, the impact of applying the optional expedients was not material, and the transition to SOFR did not have a material impact on our cash flows.

ASU 2023-07

In November 2023, the FASB issued ASU No. 2023-07, *Segment Reporting (Topic 280)*. This guidance requires a public entity, including entities with single reportable segment, to disclose significant segment expenses and other segment items on an annual and interim basis and provide in interim periods all disclosures about a reportable segment's profit or loss and assets that are currently required annually. We plan to adopt this guidance and conform with the applicable disclosures retrospectively when it becomes mandatorily effective for our annual report for the year ending December 31, 2024.

ASU 2023-09

In December 2023, the FASB issued ASU No. 2023-09, *Income Taxes (Topic 740)*. This guidance further enhances income tax disclosures, primarily through standardization and disaggregation of rate reconciliation categories and income taxes paid by jurisdiction. We plan to adopt this guidance and conform with the disclosure requirements when it becomes mandatorily effective for our annual report for the year ending December 31, 2025.

NOTE 3—RESTRICTED CASH AND CASH EQUIVALENTS

As of December 31, 2023 and 2022, we had $459 million and $1.1 billion of restricted cash and cash equivalents, respectively, for which the usage or withdrawal of such cash is contractually or legally restricted, primarily to the payment of liabilities related to the Liquefaction Projects, as required under certain debt arrangements.

NOTE 4—TRADE AND OTHER RECEIVABLES, NET OF CURRENT EXPECTED CREDIT LOSSES

Trade and other receivables, net of current expected credit losses, consisted of the following (in millions):

	December 31,	
	2023	2022
Trade receivables		
SPL and CCL	$ 525	$ 922
Cheniere Marketing	451	917
Other	4	4
Other receivables	126	101
Total trade and other receivables, net of current expected credit losses	$ 1,106	$ 1,944

NOTE 5—INVENTORY

Inventory consisted of the following (in millions):

	December 31,	
	2023	2022
LNG in-transit	$ 112	$ 356
LNG	88	212
Materials	207	194
Natural gas	35	60
Other	3	4
Total inventory	$ 445	$ 826

NOTE 6—PROPERTY, PLANT AND EQUIPMENT, NET OF ACCUMULATED DEPRECIATION

Property, plant and equipment, net of accumulated depreciation consisted of the following (in millions):

	December 31, 2023	December 31, 2022
Terminal and related assets		
Terminal and interconnecting pipeline facilities (1)	$ 34,069	$ 33,815
Land	463	451
Construction-in-process	3,480	1,685
Accumulated depreciation	(6,099)	(4,985)
Total terminal and related assets, net of accumulated depreciation	31,913	30,966
Fixed assets and other		
Computer and office equipment	37	33
Furniture and fixtures	31	20
Computer software	125	121
Leasehold improvements	43	48
Other	21	20
Accumulated depreciation	(183)	(191)
Total fixed assets and other, net of accumulated depreciation	74	51
Assets under finance leases		
Marine assets	532	533
Accumulated depreciation	(63)	(22)
Total assets under finance leases, net of accumulated depreciation	469	511
Property, plant and equipment, net of accumulated depreciation	$ 32,456	$ 31,528

(1) Includes power generation facility and associated power infrastructure located near Corpus Christi, Texas that was acquired during the year ended December 31, 2023 to mitigate power price risk associated with our anticipated increased power load at the Corpus Christi LNG Terminal.

The following table shows depreciation expense and offsets to LNG terminal costs (in millions):

	Year Ended December 31, 2023	2022	2021
Depreciation expense	$ 1,190	$ 1,113	$ 1,006
Offsets to LNG terminal costs (1)	—	204	319

(1) We recognize offsets to LNG terminal costs related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations of the respective Trains of the Liquefaction Projects during the testing phase for its construction.

Terminal and related assets

Our terminal and related assets are depreciated using the straight-line depreciation method applied to groups of LNG terminal assets with varying useful lives. The identifiable components of our terminal and related assets have depreciable lives between 6 and 50 years, as follows:

Components	Useful life (years)
LNG storage tanks	50
Natural gas pipeline facilities	40
Marine berth, electrical, facility and roads	35
Water pipelines	30
Regasification processing equipment	30
Sendout pumps	20
Liquefaction processing equipment	6-50
Other	10-30

Fixed Assets and Other

Our fixed assets and other are recorded at cost and are depreciated on a straight-line method based on estimated lives of the individual assets or groups of assets.

Assets under Finance Leases

Our assets under finance leases primarily consist of certain tug vessels and LNG vessel time charters that meet the classification of a finance lease. These assets are depreciated on a straight-line method over the respective lease term. See Note 12—Leases for additional details of our finance leases.

NOTE 7—DERIVATIVE INSTRUMENTS

We have entered into the following derivative instruments:

- commodity derivatives consisting of natural gas and power supply contracts, including those under our IPM agreements, for the development, commissioning and operation of the Liquefaction Projects and expansion projects, as well as the associated economic hedges (collectively, the **"Liquefaction Supply Derivatives"**);
- LNG derivatives in which we have contractual net settlement and economic hedges on the exposure to the commodity markets in which we have contractual arrangements to purchase or sell physical LNG (collectively, **"LNG Trading Derivatives"**); and
- foreign currency exchange (**"FX"**) contracts to hedge exposure to currency risk associated with cash flows denominated in currencies other than U.S. dollar (**"FX Derivatives"**), associated with both LNG Trading Derivatives and operations in countries outside of the United States.

We recognize our derivative instruments as either assets or liabilities and measure those instruments at fair value. None of our derivative instruments are designated as cash flow, fair value or net investment hedging instruments, and changes in fair value are recorded within our Consolidated Statements of Operations to the extent not utilized for the commissioning process, in which case such changes are capitalized.

The following table shows the fair value of our derivative instruments, which are required to be measured at fair value on a recurring basis, by the fair value hierarchy levels prescribed by GAAP (in millions):

	Fair Value Measurements as of							
	December 31, 2023				December 31, 2022			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Liquefaction Supply Derivatives asset (liability)	$ 25	$ 36	$ (2,178)	$ (2,117)	$ (66)	$ (29)	$ (9,924)	$ (10,019)
LNG Trading Derivatives asset (liability)	30	(20)	—	10	1	(47)	—	(46)
FX Derivatives liability	—	(17)	—	(17)	—	(28)	—	(28)

We value our Liquefaction Supply Derivatives and LNG Trading Derivatives using a market or option-based approach incorporating present value techniques, as needed, which incorporates observable commodity price curves, when available, and other relevant data. We value our FX Derivatives with a market approach using observable FX rates and other relevant data.

We include a significant portion of our Liquefaction Supply Derivatives as Level 3 within the valuation hierarchy as the fair value is developed through the use of internal models which incorporate significant unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants may use in valuing the asset or liability. To the extent valued using an option pricing model, we consider the future prices of energy units for unobservable periods to be a significant unobservable input to estimated net fair value. In estimating the future prices of energy units, we make judgments about market risk related to liquidity of commodity indices and volatility utilizing available market data. Changes in facts and circumstances or additional information may result in revised estimates and judgments, and actual results may differ from these estimates and judgments. We derive our volatility assumptions based on observed historical settled global LNG market pricing or accepted proxies for global LNG market pricing as well as settled domestic natural gas pricing. Such volatility assumptions also contemplate, as of the balance sheet date, observable forward curve data of such indices, as well as evolving available industry data and independent studies.

In developing our volatility assumptions, we acknowledge that the global LNG industry is inherently influenced by events such as unplanned supply constraints, geopolitical incidents, unusual climate events including drought and uncommonly mild, by historical standards, winters and summers, and real or threatened disruptive operational impacts to global energy infrastructure. Our current estimate of volatility includes the impact of otherwise rare events unless we believe market participants would exclude such events on account of their assertion that those events were specific to our company and deemed within our control. As applicable to our natural gas supply contracts, our fair value estimates incorporate market participant-based assumptions pertaining to certain contractual uncertainties, including those related to the availability of market information for delivery points, as well as the timing of both satisfaction of contractual events or states of affairs and delivery commencement. We may recognize changes in fair value through earnings that could be significant to our results of operations if and when such uncertainties are resolved.

The Level 3 fair value measurements of our natural gas positions within our Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas and international LNG prices. The following table includes quantitative information for the unobservable inputs for our Level 3 Liquefaction Supply Derivatives as of December 31, 2023:

	Net Fair Value Liability (in millions)	Valuation Approach	Significant Unobservable Input	Range of Significant Unobservable Inputs / Weighted Average (1)
Liquefaction Supply Derivatives	$(2,178)	Market approach incorporating present value techniques	Henry Hub basis spread	$(1.090) - $0.505 / $(0.060)
		Option pricing model	International LNG pricing spread, relative to Henry Hub (2)	87% - 379% / 196%

(1) Unobservable inputs were weighted by the relative fair value of the instruments.

(2) Spread contemplates U.S. dollar-denominated pricing.

Increases or decreases in basis or pricing spreads, in isolation, would decrease or increase, respectively, the fair value of our Liquefaction Supply Derivatives.

The following table shows the changes in the fair value of our Level 3 Liquefaction Supply Derivatives and LNG Trading Derivatives (in millions):

	Year Ended December 31, 2023	2022	2021
Balance, beginning of period	$ (9,924)	$ (4,036)	$ 241
Realized and change in fair value gains (losses) included in net income (loss) (1):			
Included in cost of sales, existing deals (2)	5,685	(5,120)	(2,509)
Included in cost of sales, new deals (3)	15	(1,373)	(1,796)
Purchases and settlements:			
Purchases (4)	—	—	(1)
Settlements (5)	2,045	605	29
Transfers out of level 3 (6)	1	—	—
Balance, end of period	$ (2,178)	$ (9,924)	$ (4,036)
Favorable (unfavorable) changes in fair value relating to instruments still held at the end of the period	$ 5,700	$ (6,493)	$ (4,305)

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery, as settlement is equal to contractually fixed price from trade date multiplied by contractual volume. See settlements line item in this table.

(2) Impact to earnings on deals that existed at the beginning of the period and continue to exist at the end of the period.

(3) Impact to earnings on deals that were entered into during the reporting period and continue to exist at the end of the period.

(4) Includes any day one gain (loss) recognized during the reporting period on deals that were entered into during the reporting period which continue to exist at the end of the period, in addition to any derivative contracts acquired from entities at a value other than zero on acquisition date, such as derivatives assigned or novated during the reporting period and continuing to exist at the end of the period.

(5) Roll-off in the current period of amounts recognized in our Consolidated Balance Sheets at the end of the previous period due to settlement of the underlying instruments in the current period.

(6) Transferred out of Level 3 as a result of observable market for the underlying natural gas purchase agreements.

All existing counterparty derivative contracts provide for the unconditional right of set-off in the event of default. We have elected to report derivative assets and liabilities arising from those derivative contracts with the same counterparty and the unconditional contractual right of set-off on a net basis. The use of derivative instruments exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments, in instances when our derivative instruments are in an asset position. Additionally, counterparties are at risk that we will be unable to meet our commitments in instances where our derivative instruments are in a liability position. We incorporate both our own nonperformance risk and the respective counterparty's nonperformance risk in fair value measurements depending on the position of the derivative. In adjusting the fair value of our derivative contracts for the effect of nonperformance risk, we have considered the impact of any applicable credit enhancements, such as collateral postings, set-off rights and guarantees.

Commodity Derivatives

SPL and CCL hold Liquefaction Supply Derivatives which are primarily indexed to the natural gas market and international LNG indices. As of December 31, 2023, the remaining fixed terms of the Liquefaction Supply Derivatives ranged up to approximately 15 years, some of which commence upon the satisfaction of certain events or states of affairs.

Cheniere Marketing has historically entered into, and may from time to time enter into, LNG transactions that provide for contractual net settlement. Such transactions are accounted for as LNG Trading Derivatives along with financial commodity contracts in the form of swaps or futures. The terms of LNG Trading Derivatives range up to approximately one year.

The following table shows the notional amounts of our Liquefaction Supply Derivatives and LNG Trading Derivatives (collectively, **"Commodity Derivatives"**):

	December 31, 2023		December 31, 2022	
	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives	Liquefaction Supply Derivatives	LNG Trading Derivatives
Notional amount, net (in TBtu)	14,019	49	14,504	50

(1) Inclusive of amounts under contracts with unsatisfied contractual conditions and exclusive of extension options that were uncertain to be taken as of December 31, 2023.

The following table shows the effect and location of our Commodity Derivatives recorded on our Consolidated Statements of Operations (in millions):

	Consolidated Statements of Operations Location (1)	Gain (Loss) Recognized in Consolidated Statements of Operations — Year Ended December 31, 2023	2022	2021
LNG Trading Derivatives	LNG revenues	$ 139	$ (387)	$ (1,812)
LNG Trading Derivatives	Recovery (cost) of sales	(132)	(2)	91
Liquefaction Supply Derivatives (2)	LNG revenues	(5)	2	3
Liquefaction Supply Derivatives (2)	Recovery (cost) of sales	7,912	(6,203)	(4,303)

(1) Fair value fluctuations associated with commodity derivative activities are classified and presented consistently with the item economically hedged and the nature and intent of the derivative instrument.

(2) Does not include the realized value associated with Liquefaction Supply Derivatives that settle through physical delivery.

FX Derivatives

Cheniere Marketing holds FX Derivatives to protect against the volatility in future cash flows attributable to changes in international currency exchange rates. The FX Derivatives are executed primarily to economically hedge the foreign currency exposure arising from cash flows expended for both physical and financial LNG transactions that are denominated in a currency other than the U.S. dollar. The terms of FX Derivatives range up to approximately one year.

The total notional amount of our FX Derivatives was $789 million and $619 million as of December 31, 2023 and 2022, respectively.

The following table shows the effect and location of our FX Derivatives recorded on our Consolidated Statements of Operations (in millions):

	Consolidated Statements of Operations Location	Gain (Loss) Recognized in Consolidated Statements of Operations — Year Ended December 31, 2023	2022	2021
FX Derivatives	LNG revenues	$ (24)	$ 57	$ 33

Fair Value and Location of Derivative Assets and Liabilities on the Consolidated Balance Sheets

The following table shows the fair value and location of our derivative instruments on our Consolidated Balance Sheets (in millions):

	December 31, 2023			
Consolidated Balance Sheets Location	**Liquefaction Supply Derivatives (1)**	**LNG Trading Derivatives (2)**	**FX Derivatives**	**Total**
Current derivative assets	$ 49	$ 92	$ —	$ 141
Derivative assets	863	—	—	863
Total derivative assets	912	92	—	1,004
Current derivative liabilities	(651)	(82)	(17)	(750)
Derivative liabilities	(2,378)	—	—	(2,378)
Total derivative liabilities	(3,029)	(82)	(17)	(3,128)
Derivative asset (liability), net	$ (2,117)	$ 10	$ (17)	$ (2,124)

	December 31, 2022			
Consolidated Balance Sheets Location	**Liquefaction Supply Derivatives (1)**	**LNG Trading Derivatives (2)**	**FX Derivatives**	**Total**
Current derivative assets	$ 36	$ 84	$ —	$ 120
Derivative assets	35	—	—	35
Total derivative assets	71	84	—	155
Current derivative liabilities	(2,143)	(130)	(28)	(2,301)
Derivative liabilities	(7,947)	—	—	(7,947)
Total derivative liabilities	(10,090)	(130)	(28)	(10,248)
Derivative liability, net	$ (10,019)	$ (46)	$ (28)	$ (10,093)

(1) Does not include collateral posted with counterparties by us of $3 million and $111 million as of December 31, 2023 and 2022, respectively, which are included in margin deposits on our Consolidated Balance Sheets, and collateral posted by counterparties to us of $4 million and zero as of December 31, 2023 and 2022, respectively, which are included in other current liabilities on our Consolidated Balance Sheets.

(2) Does not include collateral posted with counterparties by us of $15 million and $23 million, as of December 31, 2023 and 2022, respectively, which are included in margin deposits on our Consolidated Balance Sheets, and collateral posted by counterparties to us of $3 million and zero as of December 31, 2023 and 2022, respectively, which are included in other current liabilities on our Consolidated Balance Sheets.

Consolidated Balance Sheets Presentation

The following table shows the fair value of our derivatives outstanding on a gross and net basis (in millions) for our derivative instruments that are presented on a net basis on our Consolidated Balance Sheets:

	Liquefaction Supply Derivatives	LNG Trading Derivatives	FX Derivatives
As of December 31, 2023			
Gross assets	$ 1,272	$ 94	$ —
Offsetting amounts	(360)	(2)	—
Net assets (1)	$ 912	$ 92	$ —
Gross liabilities	$ (3,095)	$ (110)	$ (17)
Offsetting amounts	66	28	—
Net liabilities (2)	$ (3,029)	$ (82)	$ (17)
As of December 31, 2022			
Gross assets	$ 76	$ 87	$ —
Offsetting amounts	(5)	(3)	—
Net assets (1)	$ 71	$ 84	$ —
Gross liabilities	$ (10,436)	$ (132)	$ (29)
Offsetting amounts	346	2	1
Net liabilities (2)	$ (10,090)	$ (130)	$ (28)

(1) Includes current and non-current derivative assets of $141 million and $863 million, respectively, as of December 31, 2023 and $120 million and $35 million, respectively, as of December 31, 2022.

(2) Includes current and non-current derivative liabilities of $750 million and $2,378 million, respectively, as of December 31, 2023 and $2,301 million and $7,947 million, respectively, as of December 31, 2022.

NOTE 8—OTHER NON-CURRENT ASSETS, NET

Other non-current assets, net consisted of the following (in millions):

	December 31, 2023	December 31, 2022
Contract assets, net of current expected credit losses	$ 244	$ 171
Advances of cash and conveyed assets to service providers for infrastructure to support LNG terminals, net of accumulated amortization	175	170
Equity method investments (1)	111	16
Goodwill	77	77
Debt issuance costs and debt discount, net of accumulated amortization	58	60
Advance tax-related payments and receivables	20	20
Other, net	74	92
Total other non-current assets, net	$ 759	$ 606

(1) Includes investment in equity interest and capacity agreements with a pipeline developer and operator, expected to support delivery of natural gas feedstock to the Corpus Christi LNG Terminal for the Corpus Christi Stage 3 Project.

NOTE 9—NON-CONTROLLING INTEREST AND VARIABLE INTEREST ENTITIES

We own a 48.6% limited partner interest in CQP in the form of 239.9 million common units, with the remaining non-controlling limited partner interest held by Blackstone Inc., Brookfield Asset Management, Inc. (**"Brookfield"**) and the public. We also own 100% of the general partner interest and the incentive distribution rights in CQP.

CQP is a limited partnership formed by us in 2006 to own and operate the Sabine Pass LNG Terminal and related assets. Our subsidiary, Cheniere Partners GP, is the general partner of CQP. In 2012, CQP, Cheniere and Blackstone CQP Holdco LP (**"Blackstone CQP Holdco"**) entered into a unit purchase agreement whereby CQP sold 100.0 million Class B units to Blackstone CQP Holdco in a private placement. The board of directors of Cheniere Partners GP was modified to include three directors appointed by Blackstone CQP Holdco, four directors appointed by us and four independent directors mutually agreed upon by Blackstone CQP Holdco and us and appointed by us. In addition, we provided Blackstone CQP Holdco with a right to maintain one board seat on our Board of Directors (our **"Board"**). A quorum of Cheniere Partners GP directors consists of a majority of all directors, including at least two directors appointed by Blackstone CQP Holdco, two directors appointed by us and two independent directors. Blackstone CQP Holdco will no longer be entitled to appoint Cheniere Partners GP directors in the event that Blackstone CQP Holdco's ownership in CQP is less than 20% of outstanding common units and subordinated units.

As a holder of common units of CQP, we are not obligated to fund losses of CQP. However, our capital account, which would be considered in allocating the net assets of CQP were it to be liquidated, continues to share in losses of CQP. We have determined that Cheniere Partners GP is a VIE and that we, as the holder of the equity at risk, do not have a controlling financial interest due to the rights held by Blackstone CQP Holdco. However, we continue to consolidate CQP as a result of Blackstone CQP Holdco's right to maintain one board seat on our Board which creates a de facto agency relationship between Blackstone CQP Holdco and us. GAAP requires that when a de facto agency relationship exists, one of the members of the de facto agency relationship must consolidate the VIE based on certain criteria. As a result, we consolidate CQP in our Consolidated Financial Statements.

The following table presents the summarized consolidated assets and liabilities (in millions) of CQP, which are included in our Consolidated Balance Sheets. The assets in the table below may only be used to settle obligations of CQP. In addition, there is no recourse to us for the consolidated VIE's liabilities. The assets and liabilities in the table below include third party assets and liabilities of CQP only and exclude intercompany balances between CQP and Cheniere that eliminate in the Consolidated Financial Statements of Cheniere.

	December 31,	
	2023	2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 575	$ 904
Restricted cash and cash equivalents	56	92
Trade and other receivables, net of current expected credit losses	373	627
Other current assets	215	269
Total current assets	1,219	1,892
Property, plant and equipment, net of accumulated depreciation	16,212	16,725
Other non-current assets, net	309	288
Total assets	$ 17,740	$ 18,905
LIABILITIES		
Current liabilities		
Accrued liabilities	$ 811	$ 1,384
Current debt, net of discount and debt issuance costs	300	—
Current derivative liabilities	196	769
Other current liabilities	201	191
Total current liabilities	1,508	2,344
Long-term debt, net of premium, discount and debt issuance costs	15,606	16,198
Derivative liabilities	1,531	3,024
Other non-current liabilities	160	98
Total liabilities	$ 18,805	$ 21,664

NOTE 10—ACCRUED LIABILITIES

Accrued liabilities consisted of the following (in millions):

	December 31,	
	2023	2022
Natural gas purchases	$ 729	$ 1,621
Interest costs and related debt fees	399	383
LNG terminals and related pipeline costs	235	240
Compensation and benefits	266	245
LNG purchases	23	88
Other accrued liabilities	128	102
Total accrued liabilities	$ 1,780	$ 2,679

NOTE 11—DEBT

Debt consisted of the following (in millions):

	December 31, 2023	December 31, 2022
SPL:		
Senior Secured Notes:		
5.750% due 2024 (the **"2024 SPL Senior Notes"**)	$ 300	$ 2,000
5.625% due 2025	2,000	2,000
5.875% due 2026	1,500	1,500
5.00% due 2027	1,500	1,500
4.200% due 2028	1,350	1,350
4.500% due 2030	2,000	2,000
4.746% weighted average rate due 2037	1,782	1,782
Total SPL Senior Secured Notes	10,432	12,132
Working capital revolving credit and letter of credit reimbursement agreement (the **"SPL Working Capital Facility"**)	—	—
Revolving credit and guaranty agreement (the **"SPL Revolving Credit Facility"**)	—	—
Total debt - SPL	10,432	12,132
CQP:		
Senior Notes:		
4.500% due 2029	1,500	1,500
4.000% due 2031	1,500	1,500
3.25% due 2032	1,200	1,200
5.950% due 2033 (the **"2033 CQP Senior Notes"**)	1,400	—
Total CQP Senior Notes	5,600	4,200
Credit facilities (the **"CQP Credit Facilities"**)	—	—
Revolving credit and guaranty agreement (the **"CQP Revolving Credit Facility"**)	—	—
Total debt - CQP	5,600	4,200
CCH:		
Senior Secured Notes:		
7.000% due 2024	—	498
5.875% due 2025	1,491	1,491
5.125% due 2027	1,201	1,271
3.700% due 2029	1,125	1,361
3.788% weighted average rate due 2039	2,539	2,633
Total CCH Senior Secured Notes	6,356	7,254
Term loan facility agreement (the **"CCH Credit Facility"**)	—	—
Working capital facility agreement (the **"CCH Working Capital Facility"**) (1)	—	—
Total debt - CCH	6,356	7,254
Cheniere:		
4.625% Senior Notes due 2028	1,500	1,500
Revolving credit agreement (the **"Cheniere Revolving Credit Facility"**)	—	—
Total debt - Cheniere	1,500	1,500
Total debt	23,888	25,086
Current debt, net of discount and debt issuance costs	(300)	(813)
Long-term portion of discount and debt issuance costs, net	(191)	(218)
Total long-term debt, net of discount and debt issuance costs	$ 23,397	$ 24,055

(1) The CCH Working Capital Facility is classified as short-term debt as we are required to reduce the aggregate outstanding principal amount to zero for a period of five consecutive business days at least once each year.

Senior Notes

SPL Senior Secured Notes

The SPL Senior Secured Notes are senior secured obligations of SPL, ranking equally in right of payment with SPL's other existing and future senior debt that is secured by the same collateral and senior in right of payment to any of its future subordinated debt. Subject to permitted liens, the SPL Senior Secured Notes are secured on a *pari passu* first-priority basis by a security interest in all of the membership interests in SPL and substantially all of SPL's assets. SPL may, at any time, redeem all or part of the SPL Senior Secured Notes at specified prices set forth in the respective indentures governing the SPL Senior Secured Notes, plus accrued and unpaid interest, if any, to the date of redemption. The series of SPL Senior Secured Notes due in 2037 are fully amortizing according to a fixed sculpted amortization schedule, as set forth in the respective indentures.

CQP Senior Notes

The CQP Senior Notes, except the 2033 CQP Senior Notes, are jointly and severally guaranteed by each of CQP's subsidiaries other than SPL and, subject to certain conditions governing its guarantee, Sabine Pass LP and the 2033 CQP Senior Notes are jointly and severally guaranteed by each of CQP's current and future subsidiaries who guarantee the CQP Revolving Credit Facility from time to time (each a **"Guarantor"** and collectively, the **"CQP Guarantors"**). The CQP Senior Notes are senior obligations of CQP, ranking equally in right of payment with CQP's other existing and future unsubordinated debt and senior to any of its future subordinated debt. In the event that the aggregate amount of CQP's secured indebtedness and the secured indebtedness of the CQP Guarantors (other than the CQP Senior Notes or any other series of notes issued under the CQP Base Indenture) outstanding at any one time exceeds the greater of (1) $1.5 billion and (2) 10% of net tangible assets (or 15% in the case of 2033 CQP Senior Notes), the CQP Senior Notes will be secured by a first-priority lien (subject to permitted encumbrances) on substantially all the existing and future tangible and intangible assets and rights of CQP and the CQP Guarantors and equity interests in the CQP Guarantors. The liens securing the CQP Senior Notes, if applicable, will be shared equally and ratably (subject to permitted liens) with the holders of any other senior secured obligations. CQP may, at any time, redeem all or part of the CQP Senior Notes at specified prices set forth in the respective indentures governing the CQP Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

CCH Senior Secured Notes

The CCH Senior Secured Notes are jointly and severally guaranteed by CCH's subsidiaries, CCL, CCP and Corpus Christi Pipeline GP, LLC (each a **"CCH Guarantor"** and collectively, the **"CCH Guarantors"**). The CCH Senior Secured Notes are senior secured obligations of CCH, ranking senior in right of payment to any and all of CCH's future indebtedness that is subordinated to the CCH Senior Secured Notes and equal in right of payment with CCH's other existing and future indebtedness that is senior and secured by the same collateral securing the CCH Senior Secured Notes. The CCH Senior Secured Notes are secured by a first-priority security interest in substantially all of CCH's and the CCH Guarantors' assets. CCH may, at any time, redeem all or part of the CCH Senior Secured Notes at specified prices set forth in the respective indentures governing the CCH Senior Secured Notes, plus accrued and unpaid interest, if any, to the date of redemption. The series of CCH Senior Secured Notes due in 2039 are fully amortizing according to a fixed sculpted amortization schedule, as set forth in the respective indentures.

Cheniere Senior Notes

The Cheniere Senior Notes are our general senior obligations and rank senior in right of payment to all of our future obligations that are, by their terms, expressly subordinated in right of payment to the Cheniere Senior Notes and equally in right of payment with all of our other existing and future unsubordinated indebtedness. The Cheniere Senior Notes are currently unsecured, but in certain instances may become secured in the future in connection with the incurrence of additional secured indebtedness by us. When required, the Cheniere Senior Notes will be secured on a first-priority basis by a lien on substantially all of our assets and equity interests in our direct subsidiaries (other than certain excluded subsidiaries), which liens rank *pari passu* with the liens securing the Cheniere Revolving Credit Facility. As of December 31, 2023, the Cheniere Senior Notes are not guaranteed by any of our subsidiaries. In the future, any subsidiary that guarantees any of our material indebtedness will also guarantee the Cheniere Senior Notes. We may, at any time, redeem all or part of the Cheniere Senior Notes at specified prices set forth in the indenture governing the Cheniere Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2023 (in millions):

Years Ending December 31,	Principal Payments
2024	$ 300
2025	3,543
2026	1,607
2027	2,889
2028	3,091
Thereafter	12,458
Total	$ 23,888

Credit Facilities

Below is a summary of our committed credit facilities outstanding as of December 31, 2023 (in millions):

	SPL Revolving Credit Facility (1)(2)	CQP Revolving Credit Facility (1)(3)	CCH Credit Facility (4)	CCH Working Capital Facility (5)	Cheniere Revolving Credit Facility (6)
Total facility size	$ 1,000	$ 1,000	$ 3,260	$ 1,500	$ 1,250
Less:					
Outstanding balance	—	—	—	—	—
Letters of credit issued	280	—	—	155	—
Available commitment	$ 720	$ 1,000	$ 3,260	$ 1,345	$ 1,250
Priority ranking	Senior secured	Senior unsecured	Senior secured	Senior secured	Unsecured
Interest rate on available balance (7)	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.0% - 1.75% or base rate plus 0.0% - 0.75%	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.125% - 2.0% or base rate plus 0.125% - 1.0%	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.5% or base rate plus 0.5%	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.0% - 1.5% or base rate plus 0.0% - 0.5%	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.075% - 2.20% or base rate plus 0.075% - 1.2%
Commitment fees on undrawn balance (7)	0.075% - 0.30%	0.10% - 0.30%	0.525%	0.10% - 0.20%	0.115% - 0.365% (8)
Maturity date	June 23, 2028	June 23, 2028	(9)	June 15, 2027	October 28, 2026

(1) In June 2023, CQP and SPL refinanced and replaced the CQP Credit Facilities and the SPL Working Capital Facility with the CQP Revolving Credit Facility and the SPL Revolving Credit Facility, respectively, resulting in extended maturity dates, revised borrowing capacities, reduced rate of interest and commitment fees applicable thereunder and certain other changes to terms and conditions.

(2) The obligations of SPL under the SPL Revolving Credit Facility are secured by substantially all of the assets of SPL as well as a pledge of all of the membership interests in SPL and certain future subsidiaries of SPL on a *pari passu* basis by a first priority lien with the SPL Senior Secured Notes. The SPL Revolving Credit Facility contains customary contractual conditions for extensions of credit.

(3) The obligations under the CQP Revolving Credit Facility are jointly, severally and unconditionally guaranteed by Cheniere Investments, SPLNG, CTPL, Sabine Pass LNG-GP, LLC, Sabine Pass Tug Services, LLC and Cheniere Pipeline GP Interests, LLC.

(4) The obligations of CCH under the CCH Credit Facility are secured by a first priority lien on substantially all of the assets of CCH and its subsidiaries and by a pledge by CCH Holdco I of its limited liability company interests in CCH.

(5) The obligations of CCH under the CCH Working Capital Facility are secured by substantially all of the assets of CCH and the CCH Guarantors as well as all of the membership interests in CCH and each of the CCH Guarantors on a *pari passu* basis with the CCH Senior Secured Notes and the CCH Credit Facility.

(6) In June 2023, we amended the Cheniere Revolving Credit Facility to update the indexed interest rate to SOFR. The Cheniere Revolving Credit Facility contains a financial covenant requiring us to maintain a non-consolidated leverage ratio not to exceed 5.50:1.00 as of the end of any fiscal quarter if (i) as of the last day of such fiscal quarter the aggregate principal amount of outstanding loans plus drawn and unreimbursed letters of credit is greater than 35% of

the aggregate commitments under the Cheniere Revolving Credit Facility (a "**Covenant Trigger Event**") or (ii) a Covenant Trigger Event had occurred and been continuing as of the last day of the immediately preceding fiscal quarter and as of the last day of such ending fiscal quarter such Covenant Trigger Event had not ceased for a period of at least thirty consecutive days.

(7) The margin on the interest rate and the commitment fees is subject to change based on the applicable entity's credit rating.

(8) In April 2023, the commitment fees for the Cheniere Revolving Credit Facility were reduced as a result of achieving certain ESG metrics.

(9) The CCH Credit Facility matures the earlier of June 15, 2029 or two years after the substantial completion of the last Train of the Corpus Christi Stage 3 Project.

Loss on Extinguishment of Debt Related to Termination of Agreement with Chevron

Our loss on modification or extinguishment of debt for the year ended December 31, 2022 includes a loss on extinguishment of prospective payment obligations of $31 million associated with a premium paid to Chevron U.S.A. Inc. (**"Chevron"**) to terminate a revenue sharing arrangement under the terminal marine services agreement with them. See Note 13—Revenue for further discussion of the termination of agreements with Chevron.

Restrictive Debt Covenants

The indentures governing our senior notes and other agreements underlying our debt contain customary terms and events of default and certain covenants that, among other things, may limit us, our subsidiaries' and its restricted subsidiaries' ability to make certain investments or pay dividends or distributions. SPL and CCH are restricted from making distributions under agreements governing their respective indebtedness generally until, among other requirements, appropriate reserves have been established for debt service using cash or letters of credit and a historical debt service coverage ratio and projected debt service coverage ratio of at least 1.25:1.00 is satisfied. At December 31, 2023, our restricted net assets of consolidated subsidiaries were approximately $203 million.

As of December 31, 2023, each of our issuers was in compliance with all covenants related to their respective debt agreements.

Interest Expense

Total interest expense, net of capitalized interest, consisted of the following (in millions):

	Year Ended December 31,		
	2023	2022	2021
Interest cost on convertible notes:			
Interest per contractual rate	$ —	$ —	$ 36
Amortization of debt discount and debt issuance costs	—	—	10
Total interest cost related to convertible notes	—	—	46
Interest cost on debt and finance leases excluding convertible notes	1,265	1,485	1,558
Total interest cost	$ 1,265	$ 1,485	1,604
Capitalized interest	(124)	(79)	(166)
Total interest expense, net of capitalized interest	$ 1,141	$ 1,406	$ 1,438

Fair Value Disclosures

The following table shows the carrying amount and estimated fair value of our senior notes (in millions):

	December 31, 2023		December 31, 2022	
	Carrying Amount	Estimated Fair Value (1)	Carrying Amount	Estimated Fair Value (1)
Senior notes	$ 23,888	$ 23,062	$ 25,086	$ 23,500

(1) As of both December 31, 2023 and 2022, $3.0 billion of the fair value of our senior notes were classified as Level 3 since these senior notes were valued by applying an unobservable illiquidity adjustment to the price derived from trades or indicative bids of instruments with similar terms, maturities and credit standing. The remainder of our senior notes are classified as Level 2, based on prices derived from trades or indicative bids of the instruments.

The estimated fair value of our credit facilities approximates the principal amount outstanding because the interest rates are variable and reflective of market rates and the debt may be repaid, in full or in part, at any time without penalty.

NOTE 12—LEASES

Our leased assets consist primarily of LNG vessels leased under time charters (**"vessel charters"**) and additionally include tug vessels, office space and facilities and land sites. All of our leases are classified as operating leases except for certain of our vessel charters, tug vessels and marine equipment, which are classified as finance leases.

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

		December 31,	
	Consolidated Balance Sheets Location	2023	2022
Right-of-use assets—Operating	Operating lease assets	$ 2,641	$ 2,625
Right-of-use assets—Financing	Property, plant and equipment, net of accumulated depreciation	469	511
Total right-of-use assets		$ 3,110	$ 3,136
Current operating lease liabilities	Current operating lease liabilities	$ 655	$ 616
Current finance lease liabilities	Other current liabilities	35	28
Non-current operating lease liabilities	Operating lease liabilities	1,971	1,971
Non-current finance lease liabilities	Finance lease liabilities	467	494
Total lease liabilities		$ 3,128	$ 3,109

The following table shows the classification and location of our lease costs on our Consolidated Statements of Operations (in millions):

		Year Ended December 31,		
	Consolidated Statements of Operations Location	2023	2022	2021
Operating lease cost (a)	Operating costs and expenses (1)	$ 783	$ 828	$ 621
Finance lease cost:				
Amortization of right-of-use assets	Depreciation and amortization expense	50	12	3
Interest on lease liabilities	Interest expense, net of capitalized interest	35	14	9
Total lease cost		$ 868	$ 854	$ 633
(a) Included in operating lease cost:				
Short-term lease costs		$ 33	$ 122	$ 139
Variable lease costs		17	18	21

(1) Presented in the appropriate line item within operating costs and expenses, consistent with the nature of the asset under lease.

Future annual minimum lease payments for operating and finance leases as of December 31, 2023 are as follows (in millions):

Years Ending December 31,	Operating Leases	Finance Leases
2024	$ 752	$ 67
2025	612	72
2026	480	75
2027	383	77
2028	228	73
Thereafter	638	355
Total lease payments (1)	3,093	719
Less: Interest	(467)	(217)
Present value of lease liabilities	$ 2,626	$ 502

(1) Does not include approximately $3.8 billion of legally binding minimum payments for vessel charters executed as of December 31, 2023 that will commence in future periods with fixed minimum lease terms of up to 15 years.

The following table shows the weighted-average remaining lease term and the weighted-average discount rate for our operating leases and finance leases:

	December 31, 2023		December 31, 2022	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted-average remaining lease term (in years)	6.3	9.7	5.9	10.6
Weighted-average discount rate (1)	4.7%	7.7%	4.2%	7.8%

(1) The weighted average discount rate is impacted by certain finance leases that commenced prior to the adoption of the current leasing standard under GAAP. In accordance with previous accounting guidance, the implied rate is based on the fair value of the underlying assets.

The following table includes other quantitative information for our operating and finance leases (in millions):

	Year Ended December 31,		
	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 720	$ 713	$ 483
Operating cash flows from finance leases	35	14	10
Financing cash flows from finance leases	28	7	—
Right-of-use assets obtained in exchange for operating lease liabilities	646	1,220	1,736
Right-of-use assets obtained in exchange for finance lease liabilities (1)	8	473	—

(1) Includes $88 million reclassified from operating leases to finance leases during the year ended December 31, 2022 as a result of modification of the underlying vessel charters.

LNG Vessel Subcharters

We sublease certain LNG vessels under charter to third parties while retaining our existing obligation to the original lessor. All of our sublease arrangements have been assessed as operating leases. The following table shows the sublease income recognized in other revenues on our Consolidated Statements of Operations (in millions):

	Year Ended December 31,		
	2023	2022	2021
Fixed income	$ 446	$ 371	$ 72
Variable income	57	79	37
Total sublease income	$ 503	$ 450	$ 109

Future annual minimum sublease payments to be received from LNG vessel subcharters as of December 31, 2023 are as follows (in millions):

Years Ending December 31,	Sublease Payments
2024	$ 158
2025	5
Total sublease payments	$ 163

NOTE 13—REVENUES

The following table represents a disaggregation of revenue earned (in millions):

	Year Ended December 31,		
	2023	2022	2021
Revenues from contracts with customers			
LNG revenues	$ 19,459	$ 32,132	$ 17,171
Regasification revenues	135	1,068	269
Other revenues	187	107	91
Total revenues from contracts with customers	19,781	33,307	17,531
Net derivative gain (loss) (1)	110	(328)	(1,776)
Other (2)	503	449	109
Total revenues	$ 20,394	$ 33,428	$ 15,864

(1) See Note 7—Derivative Instruments for additional information about our derivatives.

(2) Primarily includes revenues from LNG vessel subcharters. See Note 12—Leases for additional information about our subleases.

LNG Revenues

We have entered into numerous SPAs with third party customers for the sale of LNG on an FOB basis (delivered to the customer at the Sabine Pass LNG Terminal or the Corpus Christi LNG Terminal, as applicable) or a DAT basis (delivered to the customer at their specified LNG receiving terminal). Our customers generally purchase LNG for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG generally equal to 115% of Henry Hub. The fixed fee component is the amount payable to us regardless of a cancellation or suspension of LNG cargo deliveries by the customers. The variable fee component is the amount generally payable to us only upon delivery of LNG plus all future adjustments to the fixed fee for inflation. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train.

We intend to primarily use LNG sourced from our Sabine Pass LNG Terminal or our Corpus Christi LNG Terminal to provide contracted volumes to our customers. However, we supplement this LNG with volumes procured from third parties. LNG revenues recognized from LNG that was procured from third parties was $359 million, $760 million and $499 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Revenues from the sale of LNG are recognized at a point in time when the LNG is delivered to the customer based on the delivery terms described above, which is the point legal title, physical possession and the risks and rewards of ownership transfer to the customer. Each individual molecule of LNG is viewed as a separate performance obligation. We allocate the contract price (including both fixed and variable fees) in each LNG sales arrangement based on the stand-alone selling price of each performance obligation as of the time the contract was negotiated. We have concluded that the variable fees meet the exception for allocating variable consideration to specific parts of the contract. As such, the variable consideration for these contracts is allocated to each distinct molecule of LNG and recognized when that distinct molecule of LNG is delivered to the customer. Because of the use of the exception, variable consideration related to the sale of LNG is also not included in the transaction price.

When we sell LNG on a DAT basis, we consider all transportation costs, including vessel chartering, loading/unloading and canal fees, as fulfillment costs and not as separate services provided to the customer within the arrangement, regardless of whether or not such activities occur prior to or after the customer obtains control of the LNG. We expense fulfillment costs as incurred unless otherwise dictated by GAAP.

Fees received pursuant to SPAs are recognized as LNG revenues only after substantial completion of the respective Train. Prior to substantial completion, sales generated during the commissioning phase are offset against the cost of construction for the respective Train, as the production and removal of LNG from storage is necessary to test the facility and bring the asset to the condition necessary for its intended use.

Sales of natural gas where, in the delivery of the natural gas to the end customer, we have concluded that we acted as a principal are presented within revenues in our Consolidated Statements of Operations, and where we have concluded that we acted as an agent are netted within cost of sales in our Consolidated Statements of Operations.

Regasification Revenues

The Sabine Pass LNG Terminal has operational regasification capacity of approximately 4 Bcf/d. Approximately 1 Bcf/d of the regasification capacity at the Sabine Pass LNG Terminal has been reserved under a long-term TUA with TotalEnergies Gas & Power North America, Inc. (**"TotalEnergies"**), under which they are required to pay fixed monthly fees to SPLNG, regardless of their use of the LNG terminal, aggregating approximately $125 million annually for 20 years that commenced in 2009, which is representative of fixed consideration in the contract. A portion of this fee is adjusted annually for inflation which is considered variable consideration. Prior to its cancellation effective December 31, 2022, SPLNG also had a TUA for 1 Bcf/d with Chevron, as further described below. Approximately 2 Bcf/d of regasification capacity of the Sabine Pass LNG Terminal has been reserved by SPL, for which the associated revenues are eliminated in consolidation.

Because SPLNG is continuously available to provide regasification service on a daily basis with the same pattern of transfer, we have concluded that SPLNG provides a single performance obligation to its customers on a continuous basis over time. We have determined that an output method of recognition based on elapsed time best reflects the benefits of this service to the customer and accordingly, LNG regasification capacity reservation fees are recognized as regasification revenues on a straight-line basis over the term of the respective TUAs.

In 2012, SPL entered into a partial TUA assignment agreement with TotalEnergies, whereby upon substantial completion of Train 5 of the SPL Project, SPL gained access to substantially all of TotalEnergies' capacity and other services provided under TotalEnergies' TUA with SPLNG. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG Terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity and permit SPL to more flexibly manage its LNG storage capacity. Notwithstanding any arrangements between TotalEnergies and SPL, payments required to be made by TotalEnergies to SPLNG will continue to be made by TotalEnergies to SPLNG in accordance with its TUA and we continue to recognize the payments received from TotalEnergies as revenue. Costs incurred to TotalEnergies are recognized in operating and maintenance expense. During the years ended December 31, 2023, 2022 and 2021, SPL recorded $132 million, $131 million and $129 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Termination Agreement with Chevron

In June 2022, Chevron entered into an agreement with SPLNG providing for the early termination of the TUA and an associated terminal marine services agreement between the parties and their affiliates (the **"Termination Agreement"**), effective July 2022, for a lump sum fee of $765 million (the **"Termination Fee"**). Obligations pursuant to the TUA and associated agreement, including Chevron's obligation to pay SPLNG capacity payments totaling $125 million annually (adjusted for inflation) from 2023 through 2029, terminated on December 31, 2022, upon SPLNG's receipt of the Termination Fee in December 2022. We allocated the $765 million Termination Fee to the terminated commitments, with $796 million in cash inflows allocable to the termination of the TUA, which was recognized ratably over the July 6, 2022 to December 31, 2022 period as regasification revenues on our Consolidated Statements of Operations, and an offsetting $31 million reported, upon receipt of the Termination Fee, as a loss on extinguishment of debt on our Consolidated Statements of Operations allocable to a premium paid to Chevron to terminate a revenue sharing arrangement with them that was accounted for as debt.

Contract Assets and Liabilities

The following table shows our contract assets, net of current expected credit losses, which are classified as other current assets, net and other non-current assets, net on our Consolidated Balance Sheets (in millions):

	December 31, 2023	December 31, 2022
Contract assets, net of current expected credit losses	$ 250	$ 186

Contract assets represent our right to consideration for transferring goods or services to the customer under the terms of a sales contract when the associated consideration is not yet due and also include consideration paid to our customers that will reduce the amount of revenue recognized as the remaining performance obligations in the contract are satisfied. The change in contract assets between the years ended December 31, 2023 and 2022 was primarily attributable to additional revenue recognized due to the delivery of LNG under certain SPAs for which the associated consideration was not yet due.

The following table reflects the changes in our contract liabilities, which we classify as deferred revenue and other non-current liabilities on our Consolidated Balance Sheets (in millions):

	Year Ended December 31, 2023
Deferred revenue, beginning of period	$ 320
Cash received but not yet recognized in revenue	218
Revenue recognized from prior period deferral	(244)
Deferred revenue, end of period	$ 294

We record deferred revenue when we receive consideration, or such consideration is unconditionally due from a customer, prior to transferring goods or services to the customer under the terms of a sales contract. Changes in deferred revenue during the years ended December 31, 2023 and 2022 are primarily attributable to differences between the timing of revenue recognition and the receipt of advance payments related to delivery of LNG under certain SPAs.

Transaction Price Allocated to Future Performance Obligations

Because many of our sales contracts have long-term durations, we are contractually entitled to significant future consideration which we have not yet recognized as revenue. The following table discloses the aggregate amount of the transaction price that is allocated to performance obligations that have not yet been satisfied:

	December 31, 2023		December 31, 2022	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues (2)	$ 111.0	9	$ 112.0	9
Regasification revenues	0.7	3	0.8	4
Total revenues	$ 111.7		$ 112.8	

(1) The weighted average recognition timing represents an estimate of the number of years during which we shall have recognized half of the unsatisfied transaction price.

(2) We may enter into contracts to sell LNG that are conditioned upon one or both of the parties achieving certain milestones such as reaching FID on a certain liquefaction Train, obtaining financing or achieving substantial completion of a Train and any related facilities. These contracts are considered completed contracts for revenue recognition purposes and are included in the transaction price above when the conditions are considered probable of being met and consideration is not otherwise constrained from ultimate pricing and receipt.

We have elected the following exemptions which omit certain potential future sources of revenue from the table above:

(1) We omit from the table above all performance obligations that are part of a contract that has an original expected duration of one year or less.

(2) The table above excludes substantially all variable consideration under our SPAs and TUAs. We omit from the table above all variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation when that performance obligation qualifies as a series. The amount of revenue from variable fees that is not included in the transaction price will vary based on the future prices of the underlying variable index, primarily Henry Hub, throughout the contract terms, to the extent customers elect to take delivery of their LNG, and adjustments to the consumer price index. Certain of our contracts contain additional variable consideration based on the outcome of contingent events and the movement of various indexes. We have not included such variable consideration in the transaction price to the extent the consideration is considered constrained due to the uncertainty of ultimate pricing and receipt. Additionally, we have excluded variable consideration related to volumes that contractually are subject to additional liquefaction capacity beyond what is currently in construction or operation. The following table summarizes the amount of variable consideration earned under contracts with customers included in the table above:

	Year Ended December 31,	
	2023	2022
LNG revenues	69 %	72 %
Regasification revenues	7 %	2 %

NOTE 14—RELATED PARTY TRANSACTIONS

Below is a summary of our related party transactions, all in the ordinary course of business, as reported on our Consolidated Statements of Operations (in millions):

	Year Ended December 31,		
	2023	2022	2021
LNG Revenues			
Natural Gas Transportation and Storage Agreements with a related party through Brookfield (1)	$ —	$ —	$ 1
Other revenues			
Operating Agreement and Construction Management Agreement with Midship Pipeline Company, LLC (**"Midship Pipeline"**) (2)	10	7	7
Cost of sales			
Natural Gas Supply Agreements (3)	—	—	162
Natural Gas Transportation and Storage Agreements with a related party through Brookfield (1)	—	—	1
Total cost of sales	—	—	163
Operating and maintenance expense			
Natural Gas Transportation and Storage Agreements with Midship Pipeline (2)	9	9	9
Natural Gas Transportation and Storage Agreements with a related party through Brookfield (1)	62	72	46

(1) This related party is partially owned by Brookfield, who indirectly owns a portion of CQP's limited partner interests.

(2) Midship Pipeline is a subsidiary of Midship Holdings, LLC, which we recognize as an equity method investment.

(3) Includes amounts recorded related to natural gas supply contracts that SPL and CCL had with related parties. These agreements ceased to be considered related party agreements during 2021, when the related party entity was acquired by a non-related party.

Below is a summary of our related party balances, all in the ordinary course of business, as reported on our Consolidated Balance Sheets (in millions):

	December 31,	
	2023	2022
Trade and other receivables, net of current expected credit losses	$ 3	$ 1
Accrued liabilities	6	1

NOTE 15—INCOME TAXES

The jurisdictional components of income (loss) before income taxes and non-controlling interest on our Consolidated Statements of Operations are as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
U.S.	$ 11,176	$ (1,575)	$ (2,317)
International	3,402	4,669	39
Total income (loss) before income taxes and non-controlling interest	$ 14,578	$ 3,094	$ (2,278)

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

	Year Ended December 31,		
	2023	2022	2021
Current:			
Federal	$ 130	$ 6	$ —
State	1	2	3
Foreign	(1)	11	5
Total current	130	19	8
Deferred:			
Federal	2,377	320	(633)
State	15	118	(89)
Foreign	(3)	2	1
Total deferred	2,389	440	(721)
Total income tax provision (benefit)	$ 2,519	$ 459	$ (713)

Our income tax rates do not bear a customary relationship to statutory income tax rates. A reconciliation of the federal statutory income tax rate of 21% to our effective income tax rate is as follows:

	Year Ended December 31,		
	2023	2022	2021
U.S. federal statutory tax rate	21.0 %	21.0 %	21.0 %
Income not taxable to Cheniere	(3.1)	(8.2)	7.2
State tax, net of federal benefit	0.1	0.5	(2.5)
Foreign-derived intangible income deduction	(0.7)	(1.2)	—
Valuation allowance	—	2.6	5.6
Other	—	0.1	—
Effective tax rate as reported	17.3 %	14.8 %	31.3 %

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

	December 31,	
	2023	2022
Deferred tax assets		
Net operating loss (**"NOL"**) carryforwards		
Federal	$ 915	$ 1,968
State	163	177
Federal and state tax credits	33	66
Derivative instruments	98	1,345
Operating lease liabilities	550	542
Other	298	311
Less: valuation allowance (1)	(147)	(143)
Total deferred tax assets	1,910	4,266
Deferred tax liabilities		
Investment in partnerships	(309)	(211)
Property, plant and equipment	(2,564)	(2,646)
Operating lease assets	(538)	(536)
Other	(18)	(9)
Total deferred tax liabilities	(3,429)	(3,402)
Net deferred tax assets (liabilities)	$ (1,519)	$ 864

(1) Valuation allowance primarily related to state NOL carryforward deferred tax assets and increased by $4 million and $80 million during the years ended December 31, 2023 and 2022, respectively, and decreased by $127 million during year ended December 31, 2021.

NOL and tax credit carryforwards

As of December 31, 2023, we had federal and state NOL carryforwards of approximately $4.3 billion and $2.2 billion, respectively. All of our NOLs have an indefinite carryforward period.

As of December 31, 2023, we had federal and state tax credit carryforwards of $32 million and $1 million, respectively, which will expire between 2028 and 2033. As of December 31, 2023, all of the federal tax credit carryforwards were foreign tax credit carryforwards.

Our NOL and tax credit carryforwards are not subject to, nor impacted by, any prior tax ownership change. We continue to monitor public trading activity in our shares to identify potential tax ownership changes that could impact our timing and ability to utilize such attributes.

Unrecognized Tax Benefits

As of December 31, 2023, we had unrecognized tax benefits of $73 million. If recognized, $66 million of unrecognized tax benefits would affect our effective tax rate in future periods. Interest and penalties related to income tax matters are recognized as part of income tax expense. Interest recognized as part of income tax provision was $4 million and zero as of December 31, 2023 and 2022, respectively, and cumulative accrued interest was $4 million and zero as of December 31, 2023 and 2022, respectively. There were no penalties associated with liabilities for unrecognized tax benefits recorded for the years ended December 31, 2023 and 2022. We do not expect the amount of our existing unrecognized tax benefit to significantly increase or decrease within the next 12 months.

We are subject to tax in the U.S. and various state and foreign jurisdictions and we are subject to periodic audits and reviews by taxing authorities. Federal and United Kingdom tax returns for the years after 2017 and state tax returns for the years after 2019 remain open for examination. Tax authorities may have the ability to review and adjust carryover attributes that were generated prior to these periods if utilized in an open tax year.

A reconciliation of the beginning and ending amounts of our unrecognized tax benefits is as follows (in millions):

	Year Ended December 31,	
	2023	2022
Balance at beginning of the year	$ 74	$ 65
Additions based on tax positions related to current year	—	10
Reductions for tax positions of prior years	(1)	(1)
Balance at end of the year	$ 73	$ 74

NOTE 16—SHARE-BASED COMPENSATION

We have granted restricted stock shares, restricted stock units, performance stock units and phantom units to employees and non-employee directors under the 2011 Incentive Plan, as amended (the **"2011 Plan"**) and the 2020 Incentive Plan (the **"2020 Plan"**). The 2011 Plan and the 2020 Plan provide for the issuance of 35.0 million shares and 8.0 million shares, respectively, of our common stock that may be in the form of various share-based performance awards as determined by the Compensation Committee of our Board (the **"Compensation Committee"**).

We initially recognize share-based compensation based upon the estimated fair value of awards.

For equity-classified share-based compensation awards, compensation cost is recognized based on the grant-date fair value and not subsequently remeasured unless modified. For liability-classified share-based compensation awards that cash settle or include an election to be cash settled, compensation costs are remeasured at fair value through settlement or maturity.

Except for awards that contain market conditions, the grant-date fair value is estimated based on our stock price on the grant date. The grant-date fair value of awards containing market conditions is estimated using a fair value model as further described herein.

For awards that contain graded vesting periods, the fair value is recognized as expense (net of any capitalization in accordance with GAAP) using the straight-line basis, generally over the term of the entire award, except when modifications may require an accelerated method. For awards that contain cliff vesting periods, the fair value is recognized as expense (net of any capitalization in accordance with GAAP) using the straight-line basis over the requisite service period.

For awards with both time and performance-based conditions, we recognize compensation cost based on the probable outcome of the performance condition at each reporting period.

The recognition period for share-based compensation costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period.

We account for forfeitures as they occur.

Total share-based compensation consisted of the following (in millions):

	Year Ended December 31,		
	2023	2022	2021
Share-based compensation costs before income taxes:			
Equity awards	$ 100	$ 112	$ 105
Liability awards	155	97	40
Total share-based compensation	255	209	145
Capitalized share-based compensation	(5)	(4)	(5)
Total share-based compensation costs before income taxes	$ 250	$ 205	$ 140
Tax benefit associated with share-based compensation costs	$ 54	$ 48	$ 33

The total unrecognized compensation cost at December 31, 2023 relating to non-vested share-based compensation arrangements consisted of the following:

	Unrecognized Compensation Cost (in millions)	Recognized over a weighted average period (years)
Restricted Stock Unit and Performance Stock Unit Awards	$ 181	1.4

Equity-Classified Awards

Restricted Stock Share Awards

Restricted stock share awards are awards of common stock that are granted to the members of our Board of Directors for their service, subject to restrictions on transfer and to a risk of forfeiture if the recipient is unaffiliated with us prior to the lapse of the restrictions. These awards vest over a one-year service period. There were nominal non-vested restricted stock share awards outstanding as of December 31, 2023.

The fair value of restricted stock share awards vested for the year ended December 31, 2023 was $1 million.

Restricted Stock Units

Restricted stock units are stock awards that contain a graded vesting period of up to three years and, with the exception of awards to certain officers which contain a cash settlement option, as described in *Liability-Classified Awards* below, will settle in stock upon vesting subject to restrictions on transfer and to a risk of forfeiture if the recipient terminates employment with us prior to the lapse of the restrictions.

The table below provides a summary of activity related to our equity-classified restricted stock units (in millions, except for per unit information):

	Units	Weighted Average Grant Date Fair Value Per Unit
Non-vested at January 1, 2023	2.3	$ 92.52
Granted	0.8	150.59
Forfeited	(0.1)	118.77
Modified to liability awards (1)	(0.2)	115.26
Vested (2)	(1.2)	84.12
Non-vested at December 31, 2023	1.6	$ 123.24

(1) See further details in *Liability-Classified Awards* below.

(2) The total fair value of shares vested was $183 million for the year ended December 31, 2023.

Performance Stock Units

Performance stock units provide for cliff vesting after a period of three years with payouts dependent upon the achievement of metrics compared to pre-established performance targets over the defined performance period, including a performance condition consisting of cumulative distributable cash flow per share, and in certain circumstances, a market condition consisting of absolute total shareholder return (**"ATSR"**) of our common stock. All performance stock units will settle in stock, with the exception of awards to certain officers which contain cash settlement features, either as granted or modified, as described in *Liability-Classified Awards* below.

Where applicable, the compensation for performance stock units containing a market condition of ATSR is based on a fair value assigned to the market metric using a Monte Carlo model as of the grant date, which utilizes level 3 inputs such as projected stock volatility and projected risk free rates and remains constant through the vesting period for the equity-settled component.

Compensation cost attributed to the performance metric will vary due to changing estimates of units to be earned, based on expected achievement of the performance metric. The number of units that may be earned at the end of the vesting period ranges from 0% up to 300% of the target award amount.

For performance stock units containing a cash-settlement feature, the compensation cost of the cash settled component is remeasured at each reporting period, as discussed in *Liability-Classified Awards* below.

The table below provides the assumptions used in estimating the fair value of unvested awards containing market conditions as of the end of the respective periods, and for which the performance period had not yet ended:

	Year Ended December 31,		
	2023	2022	2021
Fair value assumptions:			
Dividend yield (1)	— %	— %	— %
Expected volatility (2)	27.5% - 32.7%	36.4% - 40.2%	27.0% - 41.0%
Risk-free interest rate (2)	4.2% - 4.8%	4.4% - 4.7%	0.7% - 1.4%
Weighted average expected remaining term, in years	1.5	1.4	1.5

(1) The performance stock units are entitled to dividend equivalents during the performance period. Therefore, when calculating simulated returns, we applied an annual dividend yield of zero percent.

(2) Represents the range associated with individual vesting years.

The table below provides a summary of activity related to our equity-classified performance stock units (in millions, except for per unit information):

	Units	Weighted Average Grant Date Fair Value Per Unit
Non-vested at January 1, 2023	0.6	$ 92.11
Granted (1)	0.2	163.04
Incremental units achieved (2)	0.3	72.05
Forfeited	(0.1)	107.61
Modified to liability awards (3)	(0.3)	106.25
Vested (4)	(0.2)	55.26
Non-vested at December 31, 2023	0.5	$ 124.19

(1) Includes 0.1 million performance stock units granted in 2023 to certain officers containing a cash settlement cap of $3 million.

(2) Represents incremental units recognized as a result of final performance measures or estimated measures.

(3) See further details in *Liability-Classified Awards* below.

(4) The total fair value of shares vested was $36 million for the year ended December 31, 2023.

Liability-Classified Awards

Restricted stock units and performance stock units granted to certain officers may be settled in cash in lieu of shares, following approval by the Compensation Committee, in order to limit dilution from equity grants consistent with our share repurchase program under our long-term capital allocation plan, provided that we have sufficient liquidity to do so and the officers maintain certain stock ownership requirements. The Compensation Committee also has authorization from the Board to permit certain officers to make an election to cash settle their earned performance stock units that are expected to vest in 2025 and restricted stock units that are expected to vest in 2025 and 2026. Notwithstanding those awards which contain a cash settlement option, performance stock units granted to certain officers contain a cash settlement cap of $3 million.

A total of 0.5 million units were reclassified from equity to liability during the year ended December 31, 2023, as a result of modifications made for certain employees to settle certain awards in cash in lieu of shares. Under GAAP, the modifications are treated as an exchange of the original award for a new award. During the years ended December 31, 2023, 2022 and 2021, we recognized $86 million, $56 million and $18 million, respectively, in incremental expense as a result of the modifications, attributed to six, six, and five employees impacted, respectively.

During the year ended December 31, 2023, we paid $84 million to settle a total of 0.5 million liability-classified awards, which approximated the fair value of the awards on the settlement date and was inclusive of payout for an incremental 0.3 million of performance stock units based on final performance measures achieved.

As described above, liability-classified share-based compensation awards are remeasured at fair value through settlement or maturity. The fair value of non-vested liability-classified awards was $165 million and $98 million as of December 31, 2023 and 2022, respectively, and consisted of 0.2 million of unvested restricted stock units and 0.6 million of unvested performance stock units as of December 31, 2023 and 0.2 million of unvested restricted stock units and 0.1 million of unvested performance stock units as of December 31, 2022.

NOTE 17—EMPLOYEE BENEFIT PLAN

We have a defined contribution plan (**"401(k) Plan"**) which allows eligible employees to contribute up to 75% of their compensation up to the Internal Revenue Service maximum. We match each employee's deferrals (contributions) up to 6% of compensation and may make additional contributions at our discretion. Employees are immediately vested in the contributions made by us. Our contributions to the 401(k) Plan were $17 million, $16 million and $15 million for of the years ended December 31, 2023, 2022 and 2021, respectively. We have made no discretionary contributions to the 401(k) Plan to date.

NOTE 18—NET INCOME (LOSS) PER SHARE ATTRIBUTABLE TO COMMON STOCKHOLDERS

The following table reconciles basic and diluted weighted average common shares outstanding and common stock dividends declared (in millions, except per share data):

	Year Ended December 31,		
	2023	2022	2021
Net income (loss) attributable to common stockholders	$ 9,881	$ 1,428	$ (2,343)
Weighted average common shares outstanding:			
Basic	241.0	251.1	253.4
Dilutive unvested stock	1.6	2.3	—
Diluted	242.6	253.4	253.4
Net income (loss) per share attributable to common stockholders—basic (1)	$ 40.99	$ 5.69	$ (9.25)
Net income (loss) per share attributable to common stockholders—diluted (1)	$ 40.72	$ 5.64	$ (9.25)
Dividends paid per common share	$ 1.62	$ 1.385	$ 0.33

(1) Earnings per share in the table may not recalculate exactly due to rounding because it is calculated based on whole numbers, not the rounded numbers presented.

On January 26, 2024, we declared a quarterly dividend of $0.435 per share of common stock that is payable on February 23, 2024 to stockholders of record as of the close of business on February 6, 2024.

Potentially dilutive securities that were not included in the diluted net income (loss) per share computations because their effects would have been anti-dilutive were as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Unvested stock (1)	—	—	1.8
4.25% Convertible Senior Notes due 2045 (the **"2045 Cheniere Convertible Senior Notes"**) (2)	—	0.3	—
Total potentially dilutive common shares	—	0.3	1.8

(1) Includes the impact of unvested shares containing performance conditions to the extent that the underlying performance conditions are satisfied based on actual results as of the respective period end dates.

(2) The 2045 Cheniere Convertible Senior Notes were redeemed or converted in cash on January 5, 2022. However, the adoption of ASU 2020-06 on January 1, 2022 required a presumption of share settlement for the purpose of calculating the impact to diluted earnings per share during the period the notes were outstanding in 2022. Such impact was anti-dilutive as a result of the reported net loss attributable to common stockholders during the 2022 period.

NOTE 19—SHARE REPURCHASE PROGRAMS

On September 7, 2021, our Board authorized a reset in the previously existing share repurchase program to $1.0 billion, inclusive of any amounts remaining under the previous authorization as of September 30, 2021, for an additional three years beginning on October 1, 2021. On September 12, 2022, our Board authorized an increase in the existing share repurchase program by $4.0 billion for an additional three years, beginning on October 1, 2022. The following table presents information with respect to common stock repurchased under our share repurchase program (in millions, except per share data):

	Year Ended December 31,		
	2023	2022	2021
Total shares repurchased	9.54	9.35	0.10
Weighted average price paid per share	$ 155.50	$ 146.88	$ 87.32
Total cost of repurchases (1)	$ 1,484	$ 1,373	$ 9

(1) Amount excludes associated commission fees and excise taxes incurred, which are excluded costs under the repurchase program.

As of December 31, 2023, we had approximately $2.1 billion remaining under our share repurchase program. Subsequent to December 31, 2023 and through February 16, 2024, we repurchased approximately 2.9 million shares for over $450 million.

NOTE 20—COMMITMENTS AND CONTINGENCIES

Commitments

We have various future commitments under executed contracts that include unconditional purchase obligations and other commitments which do not meet the definition of a liability as of December 31, 2023 and thus are not recognized as liabilities in our Consolidated Financial Statements.

EPC Contract

CCL has a lump sum turnkey contract with Bechtel Energy Inc. (**"Bechtel"**) for the engineering, procurement and construction of the Corpus Christi Stage 3 Project. The total contract price of the EPC contract is approximately $5.7 billion, inclusive of amounts incurred under change orders through December 31, 2023. As of December 31, 2023, we had approximately $2.9 billion remaining obligations under this contract.

Natural Gas Supply, Transportation and Storage Service Agreements

SPL and CCL have physical natural gas supply contracts to secure natural gas feedstock for the SPL Project and the CCL Project, respectively. As of December 31, 2023, the remaining fixed terms of these contracts ranged up to 15 years, with renewal options for certain contracts and some of which commence upon the satisfaction of certain events or states of affairs.

Additionally, SPL and CCL have natural gas transportation and storage service agreements for the SPL Project and the CCL Project, respectively. The initial fixed terms of the natural gas transportation agreements range up to 20 years, with renewal options for certain contracts and some of which commence upon the satisfaction of certain events or states of affairs. The initial fixed term of the natural gas storage service agreements ranges up to 10 years.

As of December 31, 2023, the obligations of SPL and CCL under natural gas supply, transportation and storage service agreements for contracts in which contractual conditions were met or are currently expected to be met were as follows (in billions):

Years Ending December 31,	Payments Due to Third Parties (1) (2)	Payments Due to Related Parties (1) (3)
2024	$ 6.2	$ 0.1
2025	6.3	0.1
2026	5.9	0.1
2027	5.3	0.1
2028	4.3	0.1
Thereafter	29.5	0.8
Total	$ 57.5	$ 1.3

(1) Pricing of natural gas supply agreements is based on estimated forward prices and basis spreads as of December 31, 2023. Pricing of IPM agreements is based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Global gas market prices are based on estimates as of December 31, 2023 to the extent forward prices are not available and assume the highest price in cases of price optionality available under the agreement. Some of our contracts may not have been negotiated as part of arranging financing for the underlying assets providing the natural gas supply, transportation and storage services.

(2) Includes $0.8 billion under natural gas supply agreements with unsatisfied contractual conditions.

(3) Includes $1.0 billion under natural gas transportation and storage service agreements with unsatisfied contractual conditions.

Other Agreements

We have certain fixed commitments under SPL's partial TUA assignment agreement with TotalEnergies and other agreements of $1.4 billion. See Note 13—Revenues for further discussion of the partial TUA assignment.

We have approximately $3.8 billion of legally binding minimum payments primarily for vessel charters executed as of December 31, 2023 that will commence in future periods with fixed minimum lease terms of up to 15 years. See Note 12—Leases for further discussion of our leases, including leases for vessel charters that have not yet commenced as of December 31, 2023.

Environmental and Regulatory Matters

Our LNG terminals and pipelines are subject to extensive regulation under federal, state and local statutes, rules, regulations and laws. These laws require that we engage in consultations with appropriate federal and state agencies and that we obtain and maintain applicable permits and other authorizations. Failure to comply with such laws could result in legal proceedings, which may include substantial penalties. We believe that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

Legal Proceedings

We are, and may in the future be, involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. We recognize legal costs in connection with legal and regulatory matters as they are incurred. While the results of these litigation matters and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material impact on our operating results, financial position or cash flows.

NOTE 21—CUSTOMER CONCENTRATION

The concentration of our customer credit risk in excess of 10% of total revenues and/or trade and other receivables, net of current expected credit losses and contract assets, net of current expected credit losses was as follows:

	Percentage of Total Revenues from External Customers			Percentage of Trade and Other Receivables, Net and Contract Assets, Net from External Customers	
	Year Ended December 31,			December 31,	
	2023	2022	2021	2023	2022
Customer A	*	*	12%	*	*
Customer B	*	*	12%	*	*
Customer C	*	*	10%	*	*
Customer D	*	*	*	13%	*

* Less than 10%

The following table shows revenues from external customers attributable to the country in which the revenues were derived (in millions). We attribute revenues from external customers to the country in which the party to the applicable agreement has its principal place of business.

	Revenues from External Customers		
	Year Ended December 31,		
	2023	2022	2021
Singapore	$ 3,407	$ 3,273	$ 1,740
United Kingdom	2,908	4,642	1,246
United States	2,868	5,213	1,340
Ireland	1,596	2,726	1,838
South Korea	1,503	2,225	1,680
Spain	1,357	2,226	1,577
India	1,166	2,109	1,375
Switzerland	534	1,725	582
Germany	131	1,747	507
Other countries	4,924	7,542	3,979
Total	$ 20,394	$ 33,428	$ 15,864

NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2023	2022	2021
Cash paid during the period for interest on debt, net of amounts capitalized	$ 1,032	$ 891	$ 1,365
Cash paid for income taxes, net	117	30	4
Non-cash investing activity:			
Unpaid purchases of property, plant and equipment, net and other non-current assets	204	181	117
Share-based compensation capitalized to property, plant and equipment	5	4	5
Conveyance of property, plant and equipment in exchange for other non-current assets	—	17	—
Contribution of other non-current assets in exchange for equity method investment	30	—	—
Non-cash financing activity:			
Unpaid dividends declared on unvested common stock	3	4	1
Unpaid repurchases of treasury stock inclusive of excise taxes	23	—	—

See Note 12—Leases for supplemental cash flow information related to our leases.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Based on their evaluation as of the end of the fiscal year ended December 31, 2023, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are (1) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our Management's Report on Internal Control Over Financial Reporting is included in our Consolidated Financial Statements and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

Rule 10b5-1 under the Exchange Act provides an affirmative defense that enables prearranged transactions in securities in a manner that avoids concerns about initiating transactions at a future date while possibly in possession of material nonpublic information. Our Insider Trading Policy permits our directors and executive officers to enter into trading plans designed to comply with Rule 10b5-1. During the three-month period ending December 31, 2023, none of our executive officers or directors adopted or terminated a Rule 10b5-1 trading plan or adopted or terminated a non-Rule 10b5-1 trading arrangement (as defined in Item 408(c) of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Items 10 through 13 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2023.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Houston, Texas, Auditor Firm ID 185.

The remaining information required by this Item is incorporated by reference from Cheniere's definitive proxy statement, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2023.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements—Cheniere Energy, Inc. and Subsidiaries:

(2) Financial Statement Schedules:

All financial statement schedules have been omitted because they are not required, are not applicable, or the required information has been included in the consolidated financial statements and accompanying notes included in this Form 10-K.

(3) Exhibits:

Certain of the agreements filed as exhibits to this Form 10-K contain representations, warranties, covenants and conditions by the parties to the agreements that have been made solely for the benefit of the parties to the agreement. These representations, warranties, covenants and conditions:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other parties in connection with the negotiation of the agreements, which disclosures are not necessarily reflected in the agreements;
- may apply standards of materiality that differ from those of a reasonable investor; and
- were made only as of specified dates contained in the agreements and are subject to subsequent developments and changed circumstances.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time. These agreements are included to provide you with information regarding their terms and are not intended to provide any other factual or disclosure information about the Company or the other parties to the agreements. Investors should not rely on them as statements of fact.

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
2.1	Amended and Restated Purchase and Sale Agreement, dated as of August 9, 2012, by and among CQP, Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and the Company	CQP	8-K	10.2	8/9/2012
3.1	Restated Certificate of Incorporation of the Company	Cheniere	10-Q	3.1	8/10/2004
3.2	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere	8-K	3.1	2/8/2005

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
3.3	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere (SEC File No. 333-160017)	S-8	4.3	6/16/2009
3.4	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere	8-K	3.1	6/7/2012
3.5	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere	8-K	3.1	2/5/2013
3.6	Bylaws of the Company, as amended and restated December 9, 2015	Cheniere	8-K	3.1	12/15/2015
3.7	Amendment No. 1 to the Amended and Restated Bylaws of the Company, dated September 15, 2016	Cheniere	8-K	3.1	9/19/2016
4.1	Specimen Common Stock Certificate of the Company	Cheniere (SEC File No. 333-10905)	S-1	4.1	8/27/1996
4.2	Indenture, dated as of February 1, 2013, by and among SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee	CQP	8-K	4.1	2/4/2013
4.3	First Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1.1	4/16/2013
4.4	Second Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1.2	4/16/2013
4.5	Third Supplemental Indenture, dated as of November 25, 2013, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1	11/25/2013
4.6	Fourth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1	5/22/2014
4.7	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.6 above)	CQP	8-K	4.1	5/22/2014
4.8	Fifth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.2	5/22/2014
4.9	Sixth Supplemental Indenture, dated as of March 3, 2015, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1	3/3/2015
4.10	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.9 above)	CQP	8-K	4.1	3/3/2015
4.11	Seventh Supplemental Indenture, dated as of June 14, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	6/14/2016
4.12	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.11 above)	CQP	8-K	4.1	6/14/2016
4.13	Eighth Supplemental Indenture, dated as of September 19, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/23/2016
4.14	Ninth Supplemental Indenture, dated as of September 23, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.2	9/23/2016
4.15	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.14 above)	CQP	8-K	4.2	9/23/2016
4.16	Tenth Supplemental Indenture, dated as of March 6, 2017, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	3/6/2017
4.17	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.16 above)	CQP	8-K	4.1	3/6/2017
4.18	Eleventh Supplemental Indenture, dated as of May 8, 2020, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	SPL	8-K	4.1	5/8/2020

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.19	Form of 4.500% Senior Secured Note due 2030 (Included as Exhibit A-1 to Exhibit 4.18 above)	SPL	8-K	4.1	5/8/2020
4.20	Twelfth Supplemental Indenture, dated as of November 29, 2022, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	SPL	8-K	4.1	11/29/2022
4.21	Form of 5.900% Senior Secured Amortizing Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.20 above)	SPL	8-K	4.1	11/29/2022
4.22	Indenture, dated as of February 24, 2017, between SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	2/27/2017
4.23	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.22 above)	CQP	8-K	4.1	2/27/2017
4.24	Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.24	2/24/2022
4.25	Form of 2.95% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.24 above)	Cheniere	10-K	4.24	2/24/2022
4.26	Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.26	2/24/2022
4.27	Form of 3.17% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.26 above)	Cheniere	10-K	4.26	2/24/2022
4.28	First Supplemental Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.28	2/24/2022
4.29	Form of 3.19% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.28 above)	Cheniere	10-K	4.28	2/24/2022
4.30	Second Supplemental Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.30	2/24/2022
4.31	Form of 3.08% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.30 above)	Cheniere	10-K	4.30	2/24/2022
4.32	Third Supplemental Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.32	2/24/2022
4.33	Form of 3.10% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.32 above)	Cheniere	10-K	4.32	2/24/2022
4.34	Indenture, dated as of September 22, 2020, between the Company, as issuer, and the Bank of New York Mellon, as trustee	Cheniere	8-K	4.1	9/22/2020
4.35	First Supplemental Indenture, dated as of September 22, 2020, between the Company, as issuer, and the Bank of New York Mellon, as trustee	Cheniere	8-K	4.2	9/22/2020
4.36	Form of 4.625% Senior Secured Notes due 2028 (Included as Exhibit A-1 to Exhibit 4.35 above)	Cheniere	8-K	4.2	9/22/2020
4.37	Indenture, dated as of May 18, 2016, among CCH, as Issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as Guarantors, and The Bank of New York Mellon, as Trustee	Cheniere	8-K	4.1	5/18/2016
4.38	First Supplemental Indenture, dated as of December 9, 2016, among CCH, as Issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as Guarantors, and The Bank of New York Mellon, as Trustee	Cheniere	8-K	4.1	12/9/2016
4.39	Form of 5.875% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.39 above)	Cheniere	8-K	4.1	12/9/2016
4.40	Second Supplemental Indenture, dated as of May 19, 2017, among CCH, as issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as Guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	5/19/2017
4.41	Form of 5.125% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.41 above)	CCH	8-K	4.1	5/19/2017

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.42	Third Supplemental Indenture, dated as of September 6, 2019, among CCH, as issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as Guarantors, and The Bank of New York Mellon, as Trustee	CCH	8-K	4.1	9/12/2019
4.43	Fourth Supplemental Indenture, dated as of November 13, 2019, among CCH, as issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	11/13/2019
4.44	Form of 3.700% Note due 2029 (Included as Exhibit A-1 to Exhibit 4.44 above)	CCH	8-K	4.1	11/13/2019
4.45	Fifth Supplemental Indenture, dated as of August 24, 2021, among CCH, as issuer, CCL, CCP, and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	8/24/2021
4.46	Form of 2.742% Senior Secured Note due 2039 (Included as Exhibit A-1 to Exhibit 4.46 above)	CCH	8-K	4.1	8/24/2021
4.47	Indenture, dated as of August 20, 2020, among CCH, as issuer, and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	8/21/2020
4.48	Form of 3.52% Senior Secured Note due December 31, 2039 (Included as Exhibit A-1 to Exhibit 4.48 above)	CCH	8-K	4.1	8/21/2020
4.49	Indenture, dated as of September 27, 2019, among CCH, as issuer, and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	9/30/2019
4.50	Form of 4.80% Senior Note due December 31, 2039 (Included as Exhibit A-1 to Exhibit 4.50 above)	CCH	8-K	4.1	9/30/2019
4.51	Indenture, dated as of October 17, 2019, among CCH, as issuer, and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	10/18/2019
4.52	Form of 3.925% Senior Note due December 31, 2039 (Included as Exhibit A to Exhibit 4.52 above)	CCH	8-K	4.1	10/18/2019
4.53	Indenture, dated as of September 18, 2017, between CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/18/2017
4.54	First Supplemental Indenture, dated as of September 18, 2017, between CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.2	9/18/2017
4.55	Second Supplemental Indenture, dated as of September 11, 2018, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/12/2018
4.56	Third Supplemental Indenture, dated as of September 12, 2019, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/12/2019
4.57	Form of 4.500% Senior Notes due 2029 (Included as Exhibit A-1 to Exhibit 4.57 above)	CQP	8-K	4.1	9/12/2019
4.58	Fourth Supplemental Indenture, dated as of November 5, 2020, between CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere	10-Q	4.4	11/6/2020
4.59	Fifth Supplemental Indenture, dated as of March 11, 2021, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	3/11/2021
4.60	Form of 4.000% Senior Notes due 2031 (Included as Exhibit A-1 to Exhibit 4.60 above)	CQP	8-K	4.1	3/11/2021
4.61	Sixth Supplemental Indenture, dated as of September 27, 2021, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/27/2021

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.62	Form of 3.25% Senior Notes due 2032 (Included as Exhibit A-1 to Exhibit 4.62 above)	CQP	8-K	4.1	9/27/2021
4.63	Seventh Supplemental Indenture, dated as of September 27, 2021, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	10/1/2021
4.64	Eighth Supplemental Indenture, dated as of June 21, 2023, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	6/21/2023
4.65	Form of 5.950% Senior Notes due 2033 (Included as Exhibit A to Exhibit 4.65 above)	CQP	8-K	4.1	6/21/2023
4.66*	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934				
10.1†	Cheniere Energy, Inc. 2020 Incentive Plan	Cheniere (SEC No. 333-238261)	S-8	4.9	5/14/2020
10.2†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2020 Incentive Plan (Director)	Cheniere	10-Q	10.1	8/5/2021
10.3†*	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan (NEO) (2022)				
10.4†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan (NEO) (2023)	Cheniere	10-K	10.43	2/23/2023
10.5†*	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan (NEO) (2024)				
10.6†	Form of Performance Stock Unit Award Agreement Under the Cheniere Energy, Inc. 2020 Incentive Plan (NEO) (2022)	Cheniere	10-K	10.44	2/24/2022
10.7†	Form of Performance Stock Unit Award Agreement Under the Cheniere Energy, Inc. 2020 Incentive Plan (NEO) (2023)	Cheniere	10-K	10.46	2/23/2023
10.8†*	Form of Performance Stock Unit Award Agreement Under the Cheniere Energy, Inc. 2020 Incentive Plan (NEO) (2024)				
10.9†*	Amended and Restated Cheniere Energy, Inc. Key Executive Severance Pay Plan (Effective as of November 17, 2023) and Summary Plan Description				
10.10†	Director Deferred Compensation Plan (Effective February 10, 2022)	Cheniere	10-K	10.46	2/24/2022
10.11†	Form of Deferred Stock Unit Award Agreement Under the Director Deferred Compensation Plan	Cheniere	10-K	10.47	2/24/2022
10.12†	Employment Agreement between the Company and Jack A. Fusco, dated May 12, 2016	Cheniere	8-K	10.1	5/12/2016
10.13†	Employment Agreement Amendment between the Company and Jack Fusco, dated August 15, 2019	Cheniere	8-K	10.1	8/15/2019
10.14†	Second Employment Agreement Amendment between the Company and Jack Fusco, dated August 11, 2021	Cheniere	8-K	10.1	8/13/2021
10.15†*	Cheniere Energy, Inc. Amended and Restated Retirement Policy, dated effective January 1, 2021	Cheniere	10-K	10.49	2/25/2020
10.16†	Form of Indemnification Agreement for officers of the Company	Cheniere	8-K	10.2	5/20/2020
10.17†	Form of Indemnification Agreement for directors of the Company	Cheniere	8-K	10.1	5/20/2020
10.18†	Letter Agreement, dated February 15, 2023, between the Company and Aaron Stephenson	Cheniere	8-K	10.1	2/15/2023
10.19	Senior Revolving Credit and Guaranty Agreement, among SPL, as borrower, certain subsidiaries of the Company, The Bank of Nova Scotia, as Senior Facility Agent, Société Générale, as the Common Security Trustee, the issuing banks and lenders from time to time party thereto and other participants	SPL (SEC File No. 333-273238)	S-4	10.46	7/13/2023

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.20	Fourth Amended and Restated Common Terms Agreement, among SPL, as borrower, the Secured Debt Holder Group Representatives party thereto, the Secured Hedge Representatives party thereto, the Secured Gas Hedge Representatives party thereto and Société Générale, as the Common Security Trustee and the Intercreditor Agent	SPL (SEC File No. 333-273238)	S-4	10.44	7/13/2023
10.21	Third Amended and Restated Accounts Agreement, among SPL, certain subsidiaries of SPL, Société Générale, as the Common Security Trustee, and Citibank, N.A. as the Accounts Bank	SPL	8-K	10.3	3/23/2020
10.22	Second Amended and Restated Term Loan Facility Agreement, dated June 15, 2022, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, the lenders party thereto from time to time and Société Générale as the Term Loan Facility Agent	Cheniere	8-K	10.1	6/22/2022
10.23	Second Amended and Restated Common Terms Agreement, dated June 15, 2022, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, Société Générale, as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, and Société Générale as Intercreditor Agent, and any other facility lenders party thereto from time to time	Cheniere	8-K	10.3	6/22/2022
10.24	Second Amended and Restated Common Security and Account Agreement, dated June 15, 2022, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, the Senior Creditor Group Representatives, Société Générale as the Intercreditor Agent, Société Générale as Security Trustee and Mizuho Bank, Ltd as the Account Bank	Cheniere	8-K	10.4	6/22/2022
10.25	Amended and Restated Pledge Agreement, dated May 22, 2018, among CCH HoldCo I and Société Générale as Security Trustee	Cheniere	8-K	10.4	5/24/2018
10.26	Amended and Restated Equity Contribution Agreement, dated May 22, 2018, among CCH and the Company	Cheniere	8-K	10.5	5/24/2018
10.27	Second Amended and Restated Working Capital Facility Agreement, dated June 15, 2022, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, the lenders party thereto from time to time, the issuing banks party thereto from time to time, the swing line lenders party thereto from time to time, The Bank of Nova Scotia as Working Capital Facility Agent and Société Générale as Security Trustee	Cheniere	8-K	10.2	6/22/2022
10.28	Second Amended and Restated Revolving Credit Agreement, dated as of October 28, 2021, among the Company, the Lenders and Issuing Banks party thereto, Sumitomo Mitsui Banking Corporation, as ESG Coordinator, and Société Générale, as Administrative Agent	Cheniere	8-K	10.1	11/1/2021
10.29	First Amendment to Second Amended and Restated Revolving Credit Agreement, dated as of June 15, 2023, among the Company, the Lenders and Issuing Banks party thereto, Sumitomo Mitsui Banking Corporation, as ESG Coordinator, and Société Générale, as Administrative Agent	Cheniere	10-Q	10.2	8/3/2023
10.30	Credit Agreement, dated June 18, 2020, among the Company, the Lenders party thereto, Société Générale, as Administrative Agent, and the other agents and arrangers party thereto from time to time	Cheniere	8-K	10.1	6/19/2020
10.31	Credit and Guaranty Agreement, dated as of June 23, 2023, among CQP, as borrower, certain subsidiaries of CQP, as Subsidiary Guarantors, the lenders from time to time party thereto, Société Générale, Natixis, Sumitomo Mitsui Banking Corporation, The Bank of Nova Scotia, and Wells Fargo Bank, as Issuing Banks, MUFG Bank, LTD as Administrative Agent and Coordinating Lead Arranger, and certain arrangers and other participants	Cheniere	10-Q	10.4	8/3/2023

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.32	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL 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.)	Cheniere	8-K	10.1	11/9/2018
10.33	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: the Change Order CO-00001 Modifications to Insurance Language Change Order, dated June 3, 2019	Cheniere	10-Q	10.6	8/8/2019
10.34	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00002 Fuel Provisional Sum Closure, dated July 8, 2019, (ii) the Change Order CO-00003 Currency Provisional Sum Closure, dated July 8, 2019, (iii) the Change Order CO-00004 Foreign Trade Zone, dated July 2, 2019, (iv) the Change Order CO-00005 NGPL Gate Access Security Coordination Provisional Sum, dated July 17, 2019, (v) the Change Order CO-00006 Alternate to Adams Valves, dated August 14, 2019, (vi) the Change Order CO-00007 E-1503 to HRU Permanent Drain Piping, dated August 14, 2019, (vii) the Change Order CO-00008 Differing Subsurface Soil Conditions - Train 6 ISBL, dated August 27, 2019, (viii) the Change Order CO-00009 LNG Berth 3, dated September 25, 2019 and (ix) the Change Order CO-00010 Cold Box Redesign and Addition of Inspection Boxes on Methane Cold Box, dated September 16, 2019	Cheniere	10-Q	10.10	11/1/2019
10.35	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00011 Insurance Provisional Sum Interim Adjustment, dated October 1, 2019 and (ii) the Change Order CO-00012 Replacement of Timber Piles with Pre-Stressed Concrete Piles, dated October 30, 2019	Cheniere	10-K	10.88	2/25/2020
10.36	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00013 Cost to Comply with SPL FTZ (FTZ entries, bonded transports and receipts for AG Pipe Spools Only), dated February 10, 2020, (ii) the Change Order CO-00014 Permanent Access Road to Third Berth, dated February 10, 2020, (iii) the Change Order CO-00015 Modifications to Schedule Bonus Language, dated February 10, 2020, (iv) the Change Order CO-00016 LNG Berth 3 LNTP No 3, dated January 31, 2020 and (v) the Change Order CO-00017 Construction Doc Fender Guards and LP Fuel Gas Overpressure Interlock, dated March 18, 2020	Cheniere	10-Q	10.6	4/30/2020

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.37	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00018 Electrical Studies for GTG Grid Modification, dated April 2, 2020, (ii) the Change Order CO-00019 Third Berth - Change in 5kV Electrical Tie-In, dated April 30, 2020, (iii) the Change Order CO-00020 LNG Berth 3 LNTP No. 4, dated May 4, 2020, (iv) the Change Order CO-00021 Train 6 P1601 A/B/ Flange Changes, dated May 27, 2020 and (v) the Change Order CO-00022 Train 6 H2S Skid Modifications to Level Transmitters & GTG Pressure Range Change on PT-573 A/B, dated June 4, 2020	Cheniere	10-Q	10.9	8/6/2020
10.38	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00023 Third Berth Vapor Fence Provisional Sum Scope Removal and Closeout, dated June 22, 2020, (ii) the Change Order CO-00024 Train 6 Thermowell Upgrades, dated June 22, 2020, (iii) the Change Order CO-00025 Third Berth Bubble Curtain, dated June 22, 2020, (iv) the Change Order CO-00026 Third Berth Fuel Provisional Sum Closure Change Order, dated July 14, 2020, (v) the Change Order CO-00027 Third Berth Currency Provisional Sum Closure Change Order, dated July 20, 2020, (vi) the Change Order CO-00028 Train 6 Hot Oil WHRU PSV Bypass, dated August 11, 2020 and (vii) the Change Order CO-00029 Change in Law IMO 2020 Regulatory Change – Low Sulphur Emissions on Marine Vessels, dated August 25, 2020	Cheniere	10-Q	10.2	11/6/2020
10.39	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between the SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00030 Third Berth Soil Preparation Provisional Sum Interim Adjustment Change Order, dated September 16, 2020, (ii) the Change Order CO-00031 Provisional Sum Consolidation (PAB, Taxes & Insurance), dated October 2, 2020, (iii) the Change Order CO-00032 COVID-19 Impacts, dated October 2, 2020, (iv) the Change Order CO-00033 Third Berth - Jetty Building (00A-4041) - Clean Agent System, dated November 2, 2020 and (v) the Change Order CO-00034 Vanessa Spare Valves, dated November 18, 2020	Cheniere	10-K	10.88	2/24/2021
10.40	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00035 Impacts from Hurricanes Laura and Delta, dated December 22, 2020, (ii) the Change Order CO-00036 Third Berth - Add N2 Connection on Liquid & Hybrid SVT Loading Arm Apex, dated December 22, 2020, (iii) the Change Order CO-00037 Third Berth Design Vessels Update, dated December 22, 2020, (iv) the Change Order CO-00038 Train 6 PV-16002 & FV-15104 Valve Trim Upgrades, dated January 21, 2021, (v) the Change Order CO-00039 Third Berth Design Update to Supply Bunkering Fuel, dated February 11, 2021, (vi) the Change Order CO-00040 LNG Benchmark 7 Elevation Change, dated February 11, 2021, (vii) the Change Order CO-00041 Costs to Comply with SPL FTZ (Excluding Pipe Spools), dated February 12, 2021 and (viii) the Change Order CO-00042 COVID-19 Impacts 1Q2021, dated March 12, 2021	Cheniere	10-Q	10.2	5/4/2021

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.41	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00043 Third Berth SVT Loading Arm Spares, dated April 9, 2021, (ii) the Change Order CO-00044 Third Berth U/G Directional Drilling & Cathodic Protection Provisional Sum Closures, dated April 9, 2021, (iii) the Change Order CO-00045 Winter Storm Impacts, dated April 9, 2021, (iv) the Change Order CO-00046 NGPL Security Provisional Sum Interim Adjustment, dated June 15, 2021, (v) the Change Order CO-00047 80 Acres Bridge, dated June 15, 2021 and (vi) the Change Order CO-00048 AGRU Additions for Lean Solvent Overpressure, dated June 15, 2021	Cheniere	10-Q	10.4	8/5/2021
10.42	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00049 COVID-19 Impacts 2Q2021, dated July 6, 2021, (ii) CO-00050 Third Berth Bunkering Ship Modifications — Pre-Investment for Foundations, dated July 6, 2021, (iii) CO-00051 Thermal Oxidizer Controls Change, dated September 8, 2021, (iv) CO-00052 Third Berth Spare Beacon and Additional Cable Tray, dated September 8, 2021 and (v) CO-00053 Train 6 Gearbox Assembly Replacement for Unit 1411, dated September 24, 2021	Cheniere	10-Q	10.1	11/4/2021
10.43	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00054 80 Acres Bridge Credit, dated November 30, 2021, (ii) CO-00055 Change in Law LPDES Permit - Water Treatment Filter Washing, dated December15, 2021, (iii) CO-00056 Impacts from Hurricane Ida, dated December 15, 2021 and (iv) CO-00057 Impacts from Hurricane Nicholas, dated December 15, 2021	Cheniere	10-K	10.99	2/24/2022
10.44	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00058 COVID-19 Impacts 3Q2021, dated January 6, 2022, (ii) CO-00059 Spill Containment SIL 2 Interlock, dated January 11, 2022, (iii) the Change Order CO-00060 Third Berth Soil Preparation Provisional Sum Closure, dated March 15, 2022, (iv) the Change Order CO-00061 COVID-19 Impacts 4Q2021, dated March 15, 2022 and (v) the Change Order CO-00062 FERC Condition 61, dated March 15, 2022	Cheniere	10-Q	10.2	5/4/2022
10.45	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00063 FERC Condition 78, dated May 6, 2022, (ii) the Change Order CO-00064 FERC Impact to Pipe Installation, dated June 14, 2022, (iii) the Change Order CO-00065 Spill Containment Sil 2 Interlock, dated June 15, 2022 and (iv) the Change Order CO-00066 Marine Dredging and Management Oversight Provisional Sums Closure, dated June 16, 2022	Cheniere	10-Q	10.6	8/4/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.46	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00067 Performance and Attendance Bonus ("PAB") Provisional Sum Closure, dated August 18, 2022, (ii) the Change Order CO-00068 Performance and Attendance Bonus ("PAB") Provisional Sum Closure (Reconciliation to CO-00067), dated August 18, 2022, and (iii) the Change Order CO-00069 COVID-19 Impacts 1Q2022 and 2Q2022, dated August 29, 2022	Cheniere	10-Q	10.1	11/3/2022
10.47	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00070 80-Acres Bridge, dated October 28, 2022, (ii) the Change Order CO-00071 Mooring System Low-Tension Common Alarm, dated October 31, 2022, (iii) the Change Order CO-00072 FERC Hydrocarbon Permit Conditions, dated October 31, 2022, (iv) the Change Order CO-00073 BN#2 Beacon Pile Relocation, dated October 31, 2022 and (v) the Change Order CO-00074 FERC Condition 56: ISA 84 Gas Detection, dated October 31, 2022	Cheniere	10-K	10.92	2/23/2023
10.48	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 8, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: the Change Order CO-00075 Section 232 Duties (Final Settlement FTZ), dated December 16, 2022	Cheniere	10-Q	10.1	5/2/2023
10.49	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 8, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00076 Supplemental FERC Condition 80 Requirements, dated May 5, 2023, (ii) the Change Order CO-00077 Louisiana Sales and Use Tax Provisional Sum Closure, dated June 16, 2023, (iii) the Change Order CO-00078 Natural Gas Pipeline (NGPL) Security Coordination Provisional Sum Closure, dated June 22, 2023, (iv) the Change Order CO-00079 Insurance Provisional Sum Closure, dated July 27, 2023 and (v) the Change Order Co-00080 Borrowed Items, dated September 6, 2023	Cheniere	10-Q	10.1	11/2/2023
10.50	Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL Stage III and Bechtel Energy Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment)	Cheniere	10-Q	10.1	5/4/2022
10.51	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL Stage III and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00001 Maintaining Elevated Ground Flare Option, dated March 28, 2022, (ii) the Change Order CO-00002 Package 7 Pre-Investment of Trains 8 and 9 (Without Site Work), dated April 29, 2022 and (iii) the Change Order CO-00003 Modifications to Insurance Language, dated June 13, 2022 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.7	8/4/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.52	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00004 Currency Conversion, dated June 27, 2022, (ii) the Change Order CO-00005 Fuel Adjustment, dated July 15, 2022, (iii) the Change Order CO-00006 Removal of Laydown Yard Scope Option, dated August 2, 2022, (iv) the Change Order CO-00007 Removal of Air Bridges Scope Option, dated August 22, 2022, (v) the Change Order CO-00008 Acid Gas Flare K/O Drum, dated August 16, 2022, and (vi) the Change Order CO-00009 Package 7A (Without Site Work), dated August 16, 2022 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.2	11/3/2022
10.53	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-000010 Insurance Provisional Sum Interim Adjustment, dated September 13, 2022 and (ii) the Change Order CO-000011 Package 6 Descope and Transfer to Owner, dated September 14, 2022 (Portions of this exhibit have been omitted)	Cheniere	10-K	10.96	2/23/2023
10.54	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between Corpus Christi Liquefaction Stage III, LLC and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00012 Chart License Fee Provisional Sum Closure, dated September 16, 2022, (ii) the Change Order CO-00013 HRU Nozzles and Block Headers, dated September 21, 2022, (iii) the Change Order CO-00014 Addition of Nitrogen Receiver, dated December 13, 2022, (iv) the Change Order CO-00015 Package 6 Feed Gas Pipeline Interfaces, dated December 14, 2022, (v) the Change Order CO-00016 Old Sherwin Building Security, dated November 23, 2022, (vi) the Change Order CO-00017 Remote Monitoring Diagnostic for Mixed Refrigerant (MR) Compressors, dated December 14, 2022, (vii) the Change Order CO-00018 EFG Package #1, dated January 9, 2023, (viii) the Change Order CO-00019 Q3 2022 Commodity Price Rise and Fall (ATT MM), dated January 17, 2023, (ix) the Change Order CO-00020 ICSS Vendor Selection and EPC Warranty (Yokogawa), dated September 21, 2022 and (x) the Change Order CO-00021 Laydown Development Package, dated February 6, 2023 (Portions of this exhibit have been omitted.)	Cheniere	10-Q	10.2	5/2/2023

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.55	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between Corpus Christi Liquefaction, LLC and Bechtel Energy, Inc.: (i) the Change Order CO-00022 Refrigerant Storage Packages 1 and 2, dated February 13, 2023, (ii) the Change Order CO-00023 EFG Package #2, dated February 21, 2023, (iii) the Change Order CO-00024 Defrost Improvements (Cold Box), dated February 23, 2023, (iv) the Change Order CO-00025 Miscellaneous Design Improvements, dated February 23, 2023, (v) the Change Order CO-00026 EFG Package #3, dated February 23, 2023, (vi) the Change Order CO-00027 Addition of 86 Lockout Relay on Transformers, dated February 14, 2023, (vii) the Change Order CO-00028 Additional Duct Banks, dated September 15, 2022, (viii) the Change Order CO-00029 2022 FERC Support Hours Interim Adjustment, dated March 13, 2023, (ix) the Change Order CO-00030 Drainage Blanket (A Street), dated April 6, 2023, (x) the Change Order CO-00031 Refrigerant Storage Interface Package #3, dated April 7, 2023, (xi) the Change Order CO-00032 Q4 2022 Commodity Price Rise and Fall (ATT MM), dated April 24, 2023, (xii) the Change Order CO-00033 Lift Owner-Provided Dewar System (Nitrogen Receiver Facility), dated March 1, 2022, (xiii) the Change Order CO-00034 HAZOP Package #1 - Addition of Flame Arrestors for Oil Mist Eliminator Vent, dated April 25, 2023 and (xiv) the Change Order CO-00035 EFG Package #4 (Water Pipeline Pipe Bridge), dated May 19, 2023 (Portions of this exhibit have been omitted.)	Cheniere	10-Q	10.1	8/3/2023
10.56	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL and Bechtel Energy, Inc.: (i) the Change Order CO-00036 Payment Milestone Updates (Schedule C-1), dated June 19, 2023, (ii) the Change Order CO-00037 Geotechnical Soils Investigation Period & Security Division of Responsibility Change, dated June 20, 2023, (iii) the Change Order CO-00038 Power Monitoring System (ETAP HMI), dated June 29, 2023 and (iv) the Change Order CO-00039 EFG Firewater Connection, dated June 30, 2023 (Portions of this exhibit have been omitted.)	Cheniere	10-Q	10.2	11/2/2023

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.57*	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL and Bechtel Energy, Inc.: (i) the Change Order CO-00040 Q1 2023 Commodity Price Rise and Fall (ATT MM), dated August 29, 2023, (ii) the Change Order CO-00041 Q2 2023 Commodity Price Rise and Fall (ATT MM), dated August 29, 2023, (iii) the Change Order CO-00042 HAZOP Package #2 – Additional IPL (Pressure Transmitter Across the Strainer), dated July 5, 2023, (iv) the Change Order CO-00043 Total Condensate Flowmeter on Three (3) Inch Condensate Line, dated August 31, 2023, (v) the Change Order CO-00044 FERC Package #1 ISA 84 (Accommodation for Two Hundred and Fifty (250) Fire and Gas Detectors), dated August 31, 2023, (vi) the Change Order CO-00045 Increase LNG Rundown Line Check Valve Bypass Size to Six (6) Inches, dated August 31, 2023, (vii) the Change Order CO-00046 Add Manual Bypass Valves Around 31XV-13071, dated September 13, 2023, (viii) the Change Order CO-00047 Relocate Existing 16” Process Water Line and Provide Tie-In, dated September 8, 2023, (ix) the Change Order CO-00048 Future HRU Bypass Tie-In and Thermowell Updates, dated September 12, 2023, (x) the Change Order CO-00049 Butterfly Valves for Flare Drums, dated September 5, 2023, (xi) the Change Order CO-00050 Condensate Shroud on Condensate Rundown Line (Blue Engineering Report), dated September 12, 2023, (xii) the Change Order CO-00051 EFG Package #5 (138KV Feeder Cable), dated September 8, 2023, (xiii) the Change Order CO-00052 Defect Correction Period for Cementitious Fireproofing, dated August 7, 2023, (xiv) the Change Order CO-00053 Chart Transition Joint Spares, dated October 5, 2023, (xv) the Change Order CO-00054 CCL Tank(s) “A” and “C” Tie-In Study & Long Lead Item Purchases, dated September 19, 2023, (xvi) the Change Order CO-00055 FERC Package #2 Firewater Layout, dated September 13, 2023, (xvii) the Change Order CO-00056 HAZOP Package #3 – Stainless Steel C And D Pass Piping / Two Temperature Transmitters per Train, dated February 14, 2023, (xviii) the Change Order CO-00057 HAZOP Package #4 (“Phase Two Items”), dated October 10, 2023, (xix) the Change Order CO-00058 E-HAZOP Package #1 (“LV MCC Ride Through”), dated September 8, 2023, (xx) the Change Order CO-00059 Level Transmitter on Stand Pipe Inside Liquefaction Cold Boxes, dated October 13, 2023, (xxi) the Change Order CO-00060 Small Spill Containment (Additional Curbs), dated July 5, 2023, (xxii) the Change Order CO-00061 Remote Input/Output (RIO) Junction Box Grounding, dated October 10, 2023, (xxiii) the Change Order CO-00062 Geomembrane Liner and Geocell for Laydown 6 Channel, dated August 31, 2023, (xxiv) the Change Order CO-00063 Phased Surfacing of Permanent Plant Roads, dated August 7, 2023, (xxv) the Change Order CO-00064 Provisional Sum Interim Adjustment - Schedule KK-1 12-Month COVID Countermeasures, dated July 24, 2023, (xxvi) the Change Order CO-00065 Modification to FTZ Zone Site (Exhibit A of Attachment LL), dated August 3, 2023, (xxvii) the Change Order CO-00066 Attachment B (Contract Deliverables), dated June 2, 2023, (xxviii) the Change Order CO-00067 Sheet Pile Joint Sealing 310Q02 Sump, dated October 5, 2023, (xxix) the Change Order CO-00068 E-HAZOP Package #2 (“Phase One Items”), dated October 19, 2023, (xxx) the Change Order CO-00069 Package 6 Feed Gas Pipeline and Pig Receiver DMM, dated August 3, 2023, (xxxi) the Change Order CO-00070 Dry Flare Knockout Drum Spill Pad Drain Specification Change, dated October 5, 2023, (xxxii) the Change Order CO-00071 Viewing Platform Piles, dated October 18, 2023, (xxxiii) the Change Order CO-00072 Site Plan Update Package #1 – Re-Route Contractor’S Utility Water & Nitrogen Pipelines and Provide Power & Fiber Cables To Nitrogen Tie-In Point, dated November 2, 2023, (Portions of this exhibit have been omitted.)				

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.58	LNG Sale and Purchase Agreement (FOB), dated November 21, 2011, between SPL (Seller) and Gas Natural Aprovisionamientos SDG S.A. (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer)	CQP	8-K	10.1	11/21/2011
10.59	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated April 3, 2013, between SPL (Seller) and Gas Natural Aprovisionamientos SDG S.A. (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer)	CQP	10-Q	10.1	5/3/2013
10.60	Amendment of LNG Sale and Purchase Agreement (FOB), dated January 12, 2017, between SPL (Seller) and Gas Natural Fenosa LNG GOM, Limited (assignee of Gas Natural Aprovisionamientos SDG S.A.) (Buyer)	SPL (SEC File No. 333-215882)	S-4	10.3	2/3/2017
10.61	Letter agreement regarding change from LIBOR to SOFR, dated June 8, 2023, to LNG Sale and Purchase Agreement, dated November 21, 2011, between SPL and Naturgy LNG GOM, Limited (assignee of Gas Natural Aprovisionamientos SDG S.A.), as amended	Cheniere	10-Q	10.13	8/3/2023
10.62	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between SPL (Seller) and BG Gulf Coast LNG, LLC (Buyer)	CQP	8-K	10.1	1/26/2012
10.63	Letter agreement regarding change from LIBOR to SOFR, dated May 18, 2023, to LNG Sale and Purchase Agreement, dated January 25, 2012, between SPL and BG Gulf Coast LNG, LLC, as amended	Cheniere	10-Q	10.10	8/3/2023
10.64	LNG Sale and Purchase Agreement (FOB), dated June 2, 2014, between CCL (Seller) and Gas Natural Fenosa LNG SL (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer)	Cheniere	8-K	10.1	6/2/2014
10.65	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 27, 2018, between CCL (Seller) and Gas Natural Fenosa LNG GOM, Limited (Buyer)	Cheniere	10-Q	10.6	5/4/2018
10.66	Letter agreement regarding change from LIBOR to SOFR, dated June 8, 2023, to LNG Sale and Purchase Agreement, dated June 2, 2014, between CCL and Naturgy LNG GOM, Limited (assignee of Gas Natural Fenosa LNG SL), as amended	Cheniere	10-Q	10.9	8/3/2023
10.67	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement with eleven Cameron Parish taxing authorities, dated October 23, 2007, by and between Cheniere Marketing, Inc. and SPLNG	Cheniere	10-Q	10.7	11/6/2007
10.68	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among the Company, Cheniere Energy Partners GP, LLC, CQP, Cheniere Class B Units Holdings, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time	CQP	8-K	10.1	8/6/2012
10.69	Fourth Amended and Restated Agreement of Limited Partnership of CQP, dated February 14, 2017	CQP	8-K	3.1	2/21/2017
10.70	Amended and Restated Limited Liability Company Agreement of Cheniere GP Holding Company, LLC, dated December 13, 2013	Cheniere Holdings	8-K	10.3	12/18/2013
21.1*	Subsidiaries of the Company				
23.1*	Consent of KPMG LLP				
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 Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act				

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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 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*	Cheniere Energy Inc. Clawback Policy				
101.INS*	XBRL Instance Document				
101.SCH*	XBRL Taxonomy Extension Schema Document				
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document				
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document				
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document				
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document				
104*	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)				

(1) Exhibits are incorporated by reference to reports of Cheniere (SEC File No. 001-16383), CQP (SEC File No. 001-33366), Cheniere Energy Partners LP Holdings, LLC (**"Cheniere Holdings"**) (SEC File No. 001-36234), SPL (SEC File No. 333-192373), CCH (SEC File No. 333-215435) and SPLNG (SEC File No. 333-138916), as applicable, unless otherwise indicated.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

CHENIERE ENERGY, INC.
(Registrant)

By: /s/ Jack A. Fusco
Jack A. Fusco
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 21, 2024

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.

Signature	Title	Date
/s/ Jack A. Fusco Jack A. Fusco	President and Chief Executive Officer and Director (Principal Executive Officer)	February 21, 2024
/s/ Zach Davis Zach Davis	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 21, 2024
/s/ David Slack David Slack	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 21, 2024
/s/ G. Andrea Botta G. Andrea Botta	Chairman of the Board	February 21, 2024
/s/ Patricia K. Collawn Patricia K. Collawn	Director	February 21, 2024
/s/ Brian E. Edwards Brian E. Edwards	Director	February 21, 2024
/s/ Denise Gray Denise Gray	Director	February 21, 2024
/s/ Lorraine Mitchelmore Lorraine Mitchelmore	Director	February 21, 2024
/s/ Donald F. Robillard, Jr. Donald F. Robillard, Jr.	Director	February 21, 2024
/s/ Matthew Runkle Matthew Runkle	Director	February 21, 2024
/s/ Neal A. Shear Neal A. Shear	Director	February 21, 2024